PB88-241427

Benzene Emissions from Coke By-Product Recovery Plants: Background Information for Revised Proposed Standards

(U.S.) Environmental Protection Agency
Research Triangle Park, NC

Jun 88

U.S. Department of Commerce
National Technical Information Service
NTIS

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-450/3-83-016b
June 1988

Air

PB88-241427

EPA

Benzene Emissions from Coke By-Product Recovery Plants-Background Information for Revised Proposed Standards

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NATIONAL TECHNICAL
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U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

NESHAP

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-450/3-83-016b

2.

3. RECIPIENT'S ACCESSION NO. PB88-241427

4. TITLE AND SUBTITLE
Benzene Emissions from Coke By-Product Recovery Plants - Background Information for Revised Proposed Standards

5. REPORT DATE June 1988

6. PERFORMING ORGANIZATION CODE

7. AUTHOR(S)

8. PERFORMING ORGANIZATION REPORT NO.

9. PERFORMING ORGANIZATION NAME AND ADDRESS
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

10. PROGRAM ELEMENT NO.

11. CONTRACT/GRANT NO.

12. SPONSORING AGENCY NAME AND ADDRESS
DAA for Air Quality Planning and Standards
Office of Air and Radiation
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

13. TYPE OF REPORT AND PERIOD COVERED Final

14. SPONSORING AGENCY CODE EPA/200/04

15. SUPPLEMENTARY NOTES

16. ABSTRACT

National emission standards to control emissions of benzene from new and existing coke by-product recovery plants are being promulgated under Section 112 of the Clean Air Act. This document contains summaries of public comments, EPA responses, and a discussion of differences between the proposed and revised proposed standard.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air pollution Steel industry Pollution control National emission standards Industrial processes Coke by-product recovery Hazardous air pollutants Benzene	Air Pollution Control Benzene Stationary Sources	13B

18. DISTRIBUTION STATEMENT Unlimited

19. SECURITY CLASS (This Report) Unclassified

20. SECURITY CLASS (This page) Unclassified

21. NO. OF PAGES 277

22. PRICE A13 25.95

EPA Form 2220-1 (Rev. 4-77) PREVIOUS EDITION IS OBSOLETE

ERRATA FOR COKE BY-PRODUCT RECOVERY PLANT
BACKGROUND INFORMATION DOCUMENT FOR REVISED PROPOSED STANDARDS

This background information document (BID) responds to comments on the 1984 proposal and also serves as the basis for reproposal of a revised standard based on EPA's response to the court decision noted on page 1-1 of this BID. However, readers of this document should note that while this BID refers to "the revised proposed standard" on several pages, EPA is proposing a total of four different regulatory approaches that would result in different revised proposed standards. References in this BID to the "revised proposed standard" and associated impact data pertain to Approaches A and B presented in the preamble. All information on the revised proposed standards under Approaches C and D is presented in the preamble.

EPA-450/3-83-016b

Benzene Emissions from Coke By-Product Recovery Plants-Background Information for Revised Proposed Standards

Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

June 1988

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ENVIRONMENTAL PROTECTION AGENCY

Background Information
and Draft
Environmental Impact Statement
for Revised Proposed Standards for
Coke By-Product Recovery Plants

Prepared by:

Jack R Farmer 5/31/88

Jack R. Farmer (Date)
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1. The revised proposed national emission standards would limit emissions of benzene from existing and new coke by-product recovery plants. The revised proposed standards would implement Section 112 of the Clean Air Act and are based on the Administrator's determination of June 8, 1977 (42 FR 29332), that benzene presents a significant risk to human health as a result of air emissions from one or more stationary source categories and is therefore a hazardous air pollutant. The EPA Regions III, IV, and V are particularly affected because most plants are located in these areas.

2. Copies of this document have been sent to the following Federal Departments: Labor, Health and Human Services, Defense, Transportation, Agriculture, Commerce, Interior, and Energy; the National Science Foundation; the Council on Environmental Quality; State and Territorial Air Pollution Program Administrators; EPA Regional Administrators; Local Air Pollution Control Officials; Office of Management and Budget; and other interested parties.

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2-1 List of Commenters on 1984 Proposed National Emission Standards for Coke By-Product Recovery Plants 2-2

1. SUMMARY

On June 6, 1984, the Environmental Protection Agency (EPA) proposed national emission standards for benzene emissions from coke by-product recovery plants (49 FR 23522) under the authority of Section 112 of the Clean Air Act (CAA). Public comments were requested on the proposal in the Federal Register, and the comment period was extended, by request, to October 17, 1984 (49 FR 33904). The 20 commenters were composed mainly of affected companies and industry trade associations. Also commenting were various State and county air pollution control or environmental health departments and one environmental group. The comments that were submitted, along with responses to these comments, are summarized in this document. The EPA reconsidered the proposed standards in light of the court decision in Natural Resources Defense Council, Inc. v. EPA, 824 F.2d 1146 (D.C. Cir., July 28, 1987) and reproposed the standards in June 1988. The summary of comments and responses serves as the basis for the revisions made to the standard between proposal and reproposal.

1.1 SUMMARY OF CHANGES SINCE 1984 PROPOSAL

Since the 1984 proposal, the data base has been revised to reflect the industry operating status as of November 1984 (shortly after the close of the comment period). Based on comments received on the 1984 proposal, EPA revised the estimated nationwide impacts of control (including baseline) for furnace and foundry coke producers separately. The Administrator used the revised environmental, health, cost, and economic impacts for his reconsideration.

One major change since the 1984 proposal is the revised proposal of a zero emission limit for naphthalene processing operations, final coolers, and final-cooler cooling towers at plants producing furnace coke. The revised proposal is based on wash-oil final coolers. Another major change is that proposed standards for control of storage tanks containing light-oil, benzene-toluene-xylene (BTX) mixtures, benzene, or excess ammonia-liquor at furnace and foundry plants have been eliminated from the reproposed standards.

Other changes to the standards have been made for clarifying purposes. The definition of "coke by-product recovery plant" has been revised specifically to exclude form-coke plants. New definitions for "furnace" and "foundry" coke and coke by-product recovery plant also have been added to distinguish these industry segments in terms of the volatile content of coke produced, the length of the coking cycle and the percent of each type of coke produced annually. New definitions for "exhauster" and "tar decanter" also have been added. For gas-blanketed process vessels and light-oil sumps, monitoring provisions have been added to ensure that there are no leaks from the access hatches and covers upon reclosure after usage. The regulation also has been revised to directly cross reference the provisions of 40 CFR 61, Subpart V for equipment leak requirements. The EPA also proposes to amend Subpart V where necessary for clarification of the cross referencing.

1.2 SUMMARY OF IMPACTS OF REVISED PROPOSED ACTION

1.2.1 Environmental and Energy Impacts of Revised Proposed Action

The environmental and energy impacts of the revised proposed standards are discussed in Chapter 6 of this background information document (BID). The estimated environmental impacts have been revised since the 1984 proposal to update the operating status of the industry to November 1984. These changes are discussed in Chapter 6, "Environmental Impacts." Revised environmental impact tables and emission factors are presented in Appendix A.

Implementing the revised proposed standards would reduce nationwide benzene emissions at 44 furnace and foundry plants from the baseline level of about 26,000 megagrams/year (Mg/yr) to about 2,000 Mg/yr, a 93-percent reduction. Nationwide emissions from coke by-product recovery plants of total volatile organic compounds (VOC) including benzene also would be reduced from the baseline estimated level of 171,000 Mg/yr to about 6,000 Mg/yr, a 96-percent reduction. Assuming recovery of 21.3 liters of gas/min/Mg of coke/day, the revised proposed standards would result in a national energy savings of approximately 1,800 TJ/yr from recovered coke oven gas. Impact calculations for energy requirements and coke oven gas recovery estimates are shown in Appendix A.

1.2.2 Health Risk Impacts of Revised Proposed Action

The quantitative risk assessment conducted for the proposed standards is discussed in Appendix E of the proposal BID (Benzene Emissions from Coke By-Product Recovery Plants - Background Information for Proposed Standards, EPA-450/3-83-016a); further information is in the preamble to the proposal (49 FR 23525). The risk assessment has been revised since the 1984 proposal to update the current industry operating status and to incorporate adjusted emission factors. Other changes in the risk assessment since the 1984 proposal include a revised benzene unit risk estimate (URE), which is 17 percent higher, and an increase in the exposure modeling radius to 50 kilometers (km). Further information regarding these changes is provided in Chapter 9, "Quantitative Risk Assessment," and in Appendix D.

Annual leukemia incidence associated with baseline benzene emissions at 44 plants is estimated at 3 cases/yr. Implementation of the revised proposed standards would reduce the estimated incidence to 0.2 case/yr. The maximum individual lifetime risk (MIR) at the baseline is predicted to be 6×10^{-3}. The revised proposed standards are expected to reduce the MIR to approximately 4×10^{-4} (about 4 in 10,000).

1.2.3 Cost and Economic Impacts of Revised Proposed Action

Control costs for model by-product recovery plants are discussed in Chapter 7 of the BID for the proposed standards. This analysis has been updated since the June 1984 proposal to reflect the industry operating status as of November 1984. Other changes include the adjustment of certain cost functions and the modification of light-oil/fuel recovery credits, as applied to plants that practice the flaring of excess coke oven gas. These changes are discussed in Chapter 7, "Cost Impact." The revised cost analysis is presented in Appendix B.

Based on the revised analysis, the estimated national capital cost of the revised proposed standards for the 44 plants is estimated at about $84 million over baseline costs (1984 dollars). The total annualized cost is estimated at $16 million/yr.

The nationwide economic impact of the proposed standards is analyzed in Chapter 9 of the proposal BID. This analysis, which also has been revised and updated since the 1984 proposal, is discussed in Chapter 8 of this document; further information is presented in Appendix C. Based on the revised economic analysis, the price of foundry and foundry coke is projected to increase by less than 1 percent above baseline values. The Agency does not expect closures as a direct result of the revised proposed standards. However, many furnace and foundry plants are presently in marginal economic condition or operating at a loss, and the Agency recognizes that the standards could be a factor that would trigger closure decisions at some of these plants.

1.2.4 Other Considerations

1.2.4.1 Irreversible and Irretrievable Commitment. As discussed in Chapter 7 of the BID for the proposed standards, the control options do not involve a tradeoff between short-term environmental gains at the expense of long-term environmental losses. An increased cyanide (HCN) concentration in wastewater is expected if indirect final cooling is used instead of direct final cooling. Measured HCN air emission and calculations based on once-through cooling water indicate that about 200 g/Mg of coke could be added to wastewater for treatment. However, this increase is not anticipated to cause problems for compliance with effluent regulations.

The control options do not result in irreversible and irretrievable commitment of resources. As a result of the control options, resources such as light aromatic hydrocarbons are recovered, and emissions from the majority of affected sources are reduced substantially or eliminated.

1.2.4.2 Environmental and Energy Impacts of Delayed Standards. The environmental and energy impacts of delayed standards are discussed in Chapter 7 of the BID for the proposed standards. Although delayed promulgation of the revised proposed standards would not impact current levels of water pollution or solid waste, such a delay would result in benzene emissions from furnace and foundry plants remaining at the baseline nationwide level of nearly 26,000 Mg/yr. Total emissions of benzene and other VOC also would remain at their baseline level of about 171,000 Mg/yr. No net nationwide savings in energy use would be achieved as a result of recovered coke oven gas if implementation of the revised proposed standards were delayed.

1.2.4.3 Urban and Community Impacts. The beneficial urban and community impacts of the revised proposed standards include major reductions in benzene emissions at plant sites, many of which are located near highly populated areas. This emission reduction would reduce substantially the health risk associated with operation of coke by-product recovery plants. An added benefit to urban and community areas is the VOC emission reduction for ozone nonattainment areas.

The urban and community economic impacts associated with the revised proposed standards are discussed in Section 9.3.4 of the BID. As indicated in this analysis, closure of plants now in marginal economic condition because of market conditions could occur with resulting community impacts. However, no closures are expected as a direct result of these revised proposed standards.

2. SUMMARY OF PUBLIC COMMENTS

A total of 20 comments on the proposed standards and the BID for the 1984 proposed standards were received. A list of commenters, their affiliations, and EPA docket number assigned to their correspondence is given in Table 2-1.

For the purpose of orderly presentation, the comments have been categorized under the following topics:

• Chapter 3	Selection of Source Category
• Chapter 4	Selection of Final Standards
• Chapter 5	Emission Control Technology
• Chapter 6	Environmental Impacts
• Chapter 7	Cost Impact
• Chapter 8	Economic Impact
• Chapter 9	Quantitative Risk Assessment
• Chapter 10	Equipment Leak Detection and Repair
• Chapter 11	Recordkeeping and Reporting
• Chapter 12	Miscellaneous
• Appendix A	Environmental Impact Analysis
• Appendix B	Cost Impact Analysis
• Appendix C	Economic Impact Analysis
• Appendix D	Health Risk Impact Analysis

TABLE 2-1. LIST OF COMMENTERS ON PROPOSED NATIONAL EMISSION STANDARDS FOR COKE BY-PRODUCT RECOVERY PLANTS

Docket item number[a]	Commenter and affiliation
IV-D-1	Ronald J. Chleboski, Deputy Director Air Pollution Control Bureau Allegheny County Health Department Pittsburgh, Pennsylvania 15201
IV-D-2	George P. Ferreri, Director Air Management Administration Maryland Department of Health and Mental Hygiene Baltimore, Maryland 21201
IV-D-3	Alfred C. Little Environmental Engineer FMC Corporation 2000 Market Street Philadelphia, Pennsylvania 19103
IV-D-4	Danny L. Lewis Assistant Plant Manager Empire Coke Company Birmingham, Alabama 35259
IV-D-5	Daniel J. Goodwin, Manager Division of Air Pollution Control Illinois Environmental Protection Agency 2200 Churchill Road Springfield, Illinois 62706
IV-D-6	Glen C. Tenley, Vice President Koppers Company, Inc. 1201 Koppers Building Pittsburgh, Pennsylvania 15219
IV-D-7	James R. Zwikl Director of Environmental Control Shenango Incorporated Neville Island Pittsburgh, Pennsylvania 15225
IV-D-8	D. C. Miller, Resident Manager Phosphorus Chemical Division FMC Corporation Box 431 Kemmerer, Wyoming 83101

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[a] Footnote at end of table.

(continued)

TABLE 2-1 (continued)

Docket item number[a]	Commenter and affiliation
IV-D-9	Donald C. Lang Director, Air and Water Control Inland Steel Company Indiana Harbor Works 3210 Watling Street East Chicago, Indiana 46312
IV-D-10	Lucian M. Ferguson Executive Vice President American Coke and Coal Chemicals Institute 1800 M Street, N.W. Washington, DC 20036
IV-D-11	Lecil M. Colburn Jim Walter Corporation P.O. Box 22601 1500 North Dale Mabry Tampa, Florida 33622
IV-D-12	R. Wade Kohlmann Environmental Engineer Citizens Gas and Coke Utility 2020 North Meridan Street Indianapolis, Indiana 46202-1306
IV-D-13	David D. Doniger Senior Staff Attorney Natural Resources Defense Council, Inc. 1350 New York Avenue, N.W., Suite 300 Washington, DC 20005
IV-D-14	Neil Jay King, Esq. Wilmer, Cutler & Pickering 1666 K Street, N.W. Washington, DC 20006
IV-D-15	David M. Anderson, Director Environmental and Governmental Programs Bethlehem Steel Corporation Bethlehem, Pennsylvania 18016

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[a] Footnote at end of table.

(continued)

TABLE 2-1 (continued)

Docket item number[a]	Commenter and affiliation
IV-D-16	Terry McGuire, Chief Technical Support Division California Air Resources Board 1102 Q Street P.O. Box 2815 Sacramento, California 95812
IV-D-17	Moyer B. Edwards Director, Environmental Control Alabama By-Products Corporation First National-Southern National Building P.O. Box 10246 Birmingham, Alabama 35202
IV-D-18	Neil Jay King, Esq. Wilmer, Cutler & Pickering 1666 K Street, N.W. Washington, DC 20006
IV-D-19	Barbara Patala, Acting Chairman Committee on Environmental Matters National Science Foundation Washington, DC 20550
IV-D-33[b] and IV-D-34	Michael A. Hanson USS 208 South LaSalle Street Chicago, Illinois 60604

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[a] The docket number for this project is A-79-16. Dockets are on file at EPA Headquarters in Washington, DC, and at the Office of Air Quality Planning and Standards (OAQPS) in Durham, North Carolina.

[b] Letters numbered IV-D-20 to IV-D-32 are correspondence regarding extension of the comment period, development of regulatory definitions for furnace and foundry coke, and responses to information requests and are not comments on the 1984 proposed standards or BID.

3. SELECTION OF SOURCE CATEGORY

3.1 SELECTION OF SOURCE CATEGORY

Comment: Commenters IV-D-6, IV-D-10, IV-D-12, IV-D-14, and IV-D-17 question the selection of coke by-product recovery plants as a source category for regulation based on the benzene health risk estimates predicted at proposal in 1984. The commenters contend: (1) the scientific basis of the health risk estimates is not sufficient without verification by monitoring and an epidemiologic study of an exposed community, (2) the benzene health risk is low compared to other common risks or risks from other benzene source categories, and (3) the benzene health risk is less significant than estimated because of the exaggerated exposure assumptions applied to the risk model.

Response: Specific responses are contained in Chapter 9 to the commenter's concerns regarding the methodology and assumptions applied to the quantitative risk assessment for coke by-product recovery plants. The uncertainties and assumptions associated with the quantitative health risk assessment also are discussed in the preamble to the proposed rules (49 FR 23525), in the preamble to the revised proposed rules, and are not repeated here. As discussed in the preamble to the revised proposal, EPA determined that control of this source category is warranted to protect the public health with an ample margin of safety.

3.2 REGULATION OF MERCHANT PLANTS

Comment: Commenters IV-D-4, IV-D-6, IV-D-7, IV-D-10, IV-D-11, IV-D-12, and IV-D-17 oppose the regulation of merchant plants. The commenters argue that merchant plants generate fewer emissions compared to larger furnace plants (or other benzene source categories) and pose little or no health risk. The commenters also allege that the estimated costs per merchant plant, the cost per incident of leukemia, and the overall economic impacts are higher than predicted and would adversely impact this industry segment. The commenters also believe that the merchant plant segment was not represented properly in the BID for the 1984 proposed standards.

Response: In considering the commenters' concerns, the data base has been revised since the 1984 proposal to indicate the environmental, health, and cost impacts of controls separately for furnace and foundry plants. Merchant plants generally fall under the foundry plant industry segment. As discussed in response to comment 6.2, emission factor adjustments have been made to account for the lower emission rates characteristic of foundry plants. Environmental impact estimates for foundry plants are shown in Appendix A. As discussed in the preamble of the revised proposal, EPA determined that control is warranted to protect the public health with an ample margin of safety.

The EPA does not agree that foundry plants were represented improperly in the BID for the proposed standards. The small-sized model plant (1,000 Mg/day of coke) remains representative of sites in this industry segment--both in terms of capacities and processes practiced. Additionally, the preproposal economic analysis showed the impacts of control on furnace and foundry plant industry segments.

3.3 EXCLUSION OF FORM-COKE PLANTS

Comment: One commenter in two comments (IV-D-3 and IV-D-8) requests that the regulation be clarified to exclude form-coke plants. In support, the commenter cites separate conversations with EPA personnel who stated that the 1984 proposed standards were not intended to include form-coke plants because the process does not result in significant benzene emissions.

Response: In response to the commenter's concerns, the definition of "coke by-product recovery plant" under Section 61.131 of the 1984 proposed standards has been revised to exclude form-coke plants. As discussed in correspondence to the commenter on this subject (Docket Item IV-C-10), this exclusion was not made because of the absence of significant benzene emissions from the form-coke process. Data are insufficient to draw this conclusion, although EPA would not expect significant emissions based on a review of process description information.

The EPA's major reason for excluding the form-coke process is that the form-coke process is too different from the coke by-product recovery process to apply the standards development study. For example, only one form-coke plant currently is in operation. This plant does not recover by-products. Also, the form-coke plant has a fluidized bed process. Consequently, potential by-product materials are different in chemical composition. Because of the difference in chemical composition, the process (and control) equipment also is different from equipment (and controls) found at plants using the conventional coking process.

4. SELECTION OF REVISED PROPOSED STANDARDS

4.1 SELECTION OF LEVEL OF CONTROL

Comment: Many commenters indicate that the 1984 proposed standard should be either more stringent or less stringent. For example, commenter IV-D-14 supports control levels of 90 percent on process vessels, tar storage tanks, and tar intercepting sumps, and commenter IV-D-13 recommends levels of control that provide 100 percent benzene control regardless of costs. Commenter IV-D-13 supports the most effective emission reduction techniques for equipment leaks, storage tanks, and selection of wash-oil final coolers over tar-bottom final coolers. Selection of wash-oil final coolers (or similar, equivalent systems) also is recommended by commenters IV-D-5, IV-D-9, and IV-D-15. Conversely, many foundry coke producers argue that the economic impacts of the standard as proposed would affect their plants adversely.

Response: On July 28, 1987, the United States Court of Appeals for the District of Columbia Circuit handed down an *en banc* decision in *Natural Resources Defense Council, Inc.*, v. *EPA*, 824 F.2d 1146 (D.C. Cir., 1987), hereafter referred to as "*Vinyl Chloride*", a case concerning the emission standard EPA set under Section 112 of the Clean Air Act for vinyl chloride. The Administrator reconsidered the proposed benzene standard for coke by-product recovery plants in light of the *Vinyl Chloride* opinion. For his reconsideration, the Administrator used the revised estimates of nationwide emissions, health risks, cost, and economic impacts. These estimates were revised after the 1984 proposal based on the consideration of comments received on the proposal, on information collected from industry and other sources, and on additional technical and cost analyses. The specific details of these revisions are described in Chapters 6 through 9 of this document.

Because the Administrator followed a new policy approach in the reconsideration, his selection of the level of the standard is being published for comment in the Federal Register in a supplemental notice of proposed rulemaking. The difference between the level of the revised proposed standard and the original proposal can be found in Chapter 1 of this document. The Administrator's policy and the rationale for his decision, as well as the legal framework from the Vinyl Chloride opinion, are described in the preamble to the supplemental proposal.

4.2 REGULATORY DEFINITIONS OF FOUNDRY AND FURNACE BY-PRODUCT PLANTS

The control option chosen by EPA for the revised proposed standards would require different levels of control for final coolers and associated cooling towers at furnace plants than at foundry plants. This choice necessitated the development of definitions of foundry and furnace coke and coke by-product recovery plants for the regulation. The EPA contacted the two industry trade associations, the American Iron and Steel Institute (AISI) and the American Coke and Coal Chemicals Institute (ACCCI) to obtain additional technical information regarding these definitions. The related letters and telephone communications can be found in Docket A-79-16.

The resulting definition of foundry coke is coke that is produced from raw materials with an average of less than 26 percent volatile material by weight per charge/push cycle and that is subject to a coking period of 24 hours or more. When defining foundry coke by-product recovery plant, EPA recognized that plants that predominantly produce foundry coke are typically merchant (non-captive plants). Because of the fluctuating demand for foundry coke, some of these plants also fill some orders for furnace coke. The EPA does not intend that these be classified as furnace by-product plants, since they mainly produce foundry coke. However, as the percentage of foundry coke increases, there is a corresponding increase in benzene emissions. One reason is that furnace coke production is estimated to yield larger quantities of benzene emissions per megagram of coke produced than foundry coke. Also, typically more furnace coke can be produced from the same coke oven battery in a given period of time than foundry coke. The EPA judged that a reasonable consideration of these two factors would be to define foundry plants as producing up to 25 percent furnace coke.

Furnace coke is defined as any coke that is not foundry coke; similarly a furnace coke by-product recovery plant is one that is not a foundry coke by-product recovery plant. These definitions avoid any potential for coke production and by-product plants that are neither furnace nor foundry.

There are a few independent firms that make close to 50 percent furnace and 50 percent foundry coke that would be considered furnace coke by-product plants for this reproposed benzene regulation. The Agency does not believe that it is necessary to develop a special category to examine every particular situation when developing national regulations. However, the economic analysis used company-specific financial data to the extent possible and modeled these firms as being merchant plants, rather than captive to steel companies. The analysis shows no significant adverse economic affects on these companies with control alternatives that included wash-oil final coolers proposed to control final-coolers and cooling towers at furnace plants.

5. EMISSION CONTROL TECHNOLOGY

5.1 DEMONSTRATION OF CONTROL TECHNOLOGY

Comment: Two commenters (IV-D-10 and IV-D-12) claim that gas-blanketing controls are no longer demonstrated and, consequently, are unproven. The commenters cite closure of the Armco-Houston plant and claim that the controls are not demonstrated elsewhere. One commenter adds that the firm previously designing and constructing the controls no longer participates in that business, implying that a lack of design and engineering services impairs "demonstration" of the Armco-Houston system. Also, commenters IV-D-7 and IV-D-14 allege that EPA conclusions regarding the system's safety are based on the limited experience at Armco-Houston and other plants.

Response: The EPA disagrees with these commenters. Not only does Armco-Houston's closure have no effect on the successful use of gas-blanketing controls at this plant for the 4-year period prior to closure, but gas-blanketing systems currently are used at four other plant sites.

The systems used at other plants are described in Chapter 4 of the BID for the 1984 proposed standards and in the preamble to the proposal in 49 FR 23530 (see also Docket Items II-B-45, II-B-46, and II-B-47). Gas blanketing has been used since 1960 in Plant A at Bethlehem Steel, Sparrows Point. In Plant B, the gas-blanketing system installed during 1954 was replaced during 1978 as part of the conversion to a wash-oil final-cooler system. In Plants A and B, coke-oven gas from the wash-oil scrubbers is used to blanket wash-oil decanters, circulation tanks, collecting tanks, and wastewater storage tanks. Gas blanketing also has been used since 1960 at the Republic Steel-Cleveland Coke Plant No. 1. Updated in 1978, the system currently is applied to wash-oil decanters, circulating tanks, rectifier separators, primary and secondary light-oil separators, condensers, and final-cooler circulating tanks. In Coke Plant No. 2, clean coke-oven gas from the battery underfire system is applied to primary and secondary light-oil separators, rectifier separators, and wash-oil circulation tanks. At the four Bethlehem and Republic Steel sites, gas-blanketing systems were installed initially to prevent oxidation and sludge formation in light-oil plant lines and equipment.

At Armco-Houston, four gas-blanketing techniques were applied to light-oil and tar separation equipment. The system incorporated blanketing from the gas holder for light-oil recovery vessels, gas blanketing from the collecting main for tar decanters and a flushing liquor-collecting tank, negative pressure venting of tar-collecting tanks to the primary coolers, and gas blanketing from the wash-oil final cooler (i.e., a slip stream of wash oil containing naphthalene is removed and routed to a wash-oil decanter tank).

The Armco-Houston system was installed between 1976 and 1977 according to an emission control agreement with the Texas Air Control Board (TACB). Prior to 1977, natural gas had been used to underfire the ovens; the coke oven gas was flared with no by-product recovery. Although the plant had been scheduled for shutdown in 1976, TACB agreed to continued operation with installation of emission controls. The system was operated for 4 years with no significant problems until the plant closed in March 1981. The closure was the result of economic conditions, not failure of the control system. Although their shutdown is unfortunate, it does not detract from the proven effectiveness or viability of the emission control systems employed. Thus, EPA does not consider that the closure in any way affects demonstration of the controls or application of the system at other plants.

One commenter mentions that Koppers' Engineering Construction Division (which designed and constructed the Armco system) no longer engages in that line of business. According to the commenter, this impairs the "demonstration" of the system. The EPA disagrees. This company's business decision has no relevance on whether the system has been demonstrated. Other major engineering design and construction firms are available for this service. In particular, Dravo/Still Corporation has designed and installed a positive-pressure gas-blanketing system in an existing European coke by-product plant. The system uses clean coke oven gas (at about 1 inch [2.54 cm] of water positive pressure) to blanket a variety of storage tanks and process vessels. There are no domestic installations of this system at present. However, Dravo/Still has had discussions with at least one U.S. coke plant operator about such a system for the operator's plant.

5.2 SAFETY, DESIGN, AND OPERATION OF POSITIVE-PRESSURE CONTROL SYSTEM

Comment: Commenters IV-D-3, IV-D-4, IV-D-6, IV-D-7, IV-D-14, IV-D-17, and IV-D-34 argue that gas-blanketing systems, although appropriate and cost-effective for some plants, should not be mandatory at all sites because of safety, design, and operational concerns. One commenter states that in some existing plants, redesign of the process operations and installation of new equipment will be necessary for gas-blanketing systems to work safely and effectively. Without these changes, the commenter questions the safety of positive-pressure blanketing systems, contending that leaks from older pieces of equipment that are difficult to seal effectively (e.g., tar decanters and tar storage tanks) present a potential explosion or fire hazard. One of the commenters submitted a qualitative comparative study of the safety of gas blanketing for one of their plants. The report concluded that gas blanketing would involve a significant increase in risk to operating personnel and the surrounding community. Other commenters argue that leaks from covers, gaskets, and connections in the piping system pose an explosion danger that is aggravated by the large number of sources, the presence of electrical equipment, and the vehicular traffic in areas where blanketing systems would be installed. Two commenters add that the probability of leaks (and the associated safety hazard) increases with the long pipe runs needed at some sites to connect the sources to the system. Other operational concerns cited by the commenters include the possibility of naphthalene clogging in cold climates if steam or electrical power for heated lines were lost and the chance of product contamination (benzene or light-oil) from the sulfur content of the coke-oven gases.

Response: The safety of recommended control systems should always be considered, and a system considered inherently unsafe would not be selected by EPA as a viable control technique. As discussed above in response to comment 5.1, gas blanketing has been demonstrated as safe and effective during an operating period of more than 24 years (1960 to 1984) at four plant sites in addition to Armco-Houston. In fact, in direct contradiction to the commenters' statements, EPA considers that the proposed system will improve the safety level found in uncontrolled by-product plant environments. The reasons for this conclusion are explained below.

Leaks in a negative-pressure system are discussed in response to comment 5.3, but the AISI argues that even leaks in a positive-pressure system may allow oxygen infiltration, causing tank vapors to reach explosive limits and creating a potential safety hazard. The commenter then cites preamble text in 49 FR 23530 to support this assertion. As shown below, however, the preamble statement in 49 FR 23530 clearly refers to the safety and operational advantages of blanketing from the gas holder, not to the possibility of explosion because of oxygen infiltration:

> One advantage of blanketing with clean coke oven gas from the gas holder is the elimination of oxidation reactions between oxygen in the air and organic materials in the vessels. These reactions often result in a sludge that may pose fouling and plugging problems in lines and process equipment. In addition, oxygen infiltration can cause tank vapors to reach the explosive limits of vapor when tanks are periodically emptied or when significant cooling takes place. Applying a positive pressure blanket would eliminate oxygen infiltration and maintain the vapor space in the tank above its upper explosive limit [emphasis added].

The AISI also contends that "the low positive pressure of the proposed system is insufficient to alleviate explosive conditions if leaks occur." The standards do not dictate an overall pressure level for system operation. The system installed may be based on positive or negative pressure or on a combination of the two. The pressure maintained will vary by necessity according to the type of source and location of the connections to the system (i.e., at the main or the gas holder) and overall process design.

If, as the commenter asserts, leaks in the system occur or the positive-pressure blanket fails, the possibility of an explosive atmosphere forming certainly is no greater than the possibility under current plant conditions. At most uncontrolled plant sites, explosive conditions are now present. Liquid organics float on the surface of open sumps and trenches and leak from equipment components and piping systems throughout the plant. Organic vapors also are released from "breathing" tanks as air enters venting systems or through holes in the covers. The breathing loss is recognized particularly at the light-oil condenser vent, where a continuous steam purge may operate. In EPA's judgment, enclosing these sources and ducting the emissions back to the process via a closed positive-pressure system will reduce substantially the explosion hazard that now exists. The EPA does recognize that some sources at existing plants such as tar decanters and tar tanks may be in poor condition and will require upgrading to accept gas blanketing. The necessary modifications for typical plants, however, have been reflected in the cost estimates.

The Agency also reviewed the qualitative assessment submitted by the commenter to support the contention that gas blanketing would involve a significant increase in risk to operating personnel and the surrounding community. However, EPA does not believe that such a conclusion can be drawn from the assessment for several reasons. First, the assessment is qualitative; it does not draw quantitative conclusions as to the frequency of a major system failure. In the comparative risk assessment, probability ratings were assigned to various hazards within the plant. For example, for explosion potential under current plant conditions, a probablity rating of "D" which means "likely to occur 1 time every 10 years" was assigned. With coke gas blanketing, the explosion potential was reduced to "C" which means "likely to occur every 100 years." However, with gas blanketing, higher ratings were assigned to the potential for explosion propagation, on-site safety, and financial loss. These types of ratings were assigned to various plant operations and to various control scenarios. The results were weighted and combined to provide a relative qualitative rating that may be used in evaluating options in terms of economics and safety.

Moreover, EPA does not believe the conclusions in the report are warranted for the following reasons: (1) the report did not utilize a gas-blanketing design for the plant on which to base a quantitative comparision; without a specific design; it is not possible to evaluate safety features that could be engineered into the system, (2) the assessment was based on a review of the existing conditions in the plant, without consideration of the substantial upgrading of the coke plant equipment that would be necessary to accommodate installation of a gas-blanketing system, and (3) the report did not provide any basis or criteria for assigning the probability ratings or consequence categories that are reported. After reviewing the assessment, EPA remains convinced that the upgrading of equipment needed to accommodate gas blanketing, together with the installation of a control system that is well-designed with safety features included and that is well operated and maintained will improve existing safety conditions at the sites.

The EPA recognizes that leaks in a blanketing system will occur occasionally because of the gradual deterioration of sealing materials. The prompt repair of these leaks, as required by the standards, not only ensures proper operation and maintenance of the system but also promotes safety by eliminating the leak sources. With application of a diligent leak detection and repair program, the blanketing system will not become a "network of leaks," as asserted by one commenter. In fact, if the system is allowed to deteriorate, the owner or operator will likely be found in violation of the standards.

Other commenters allege that leaks of pressurized gas from the blanketing system will create a potential explosion hazard around associated process equipment and that this hazard is aggravated by the large number of sources, coupled with the presence of electrical equipment and vehicular traffic in gas-blanketed areas. The EPA's review of the safety aspects of the proposed system does not support this contention. Hydrogen and methane are the major components of coke-oven gas, accounting for 69 to 97 percent of the emission stream. According to National Fire Code (NFC) guidelines, these lighter-than-air gases seldom produce hazardous mixtures (i.e., presenting a fire or explosion danger) in the zones where most electrical connections are made.

Although special precautions such as explosion-proof electrical components may be required where light oil or benzene is stored, this equipment should be already in place at plants where the NFC or plant safety codes have required their installation. In addition, the authors of the NFC guidelines state that, in their experience, it generally has not been necessary to classify as hazardous "locations that are adequately ventilated where flammable substances are contained in suitable, well-maintained, closed piping systems which include only the pipes, valves, fittings, flanges, and meters." The NFC recommends a common-sense safety approach. The guidelines encourage using a positive-pressure system, avoiding contact with electrical equipment or using only intrinsically safe electrical systems with low power needs, or applying a general purpose enclosure to isolate the leak area (Docket Item II-C-132).

Two commenters assert that the safety problem increases with the long pipe runs needed in some cases to connect the sources to the system. Long pipe runs for coke-oven gas already exist in many plants because the gas is used as fuel in other areas of the steel plant. The EPA contends that a long pipe run associated with a coke-oven gas-blanketing system poses no more risk than even longer pipe runs for transporting the coke-oven gas throughout the plant.

Prior to proposal of the standard in 1984, EPA thoroughly evaluated the safety aspects of gas-blanketing systems. This review included visits to each of the five plant sites with blanketing systems to discuss safety and operating problems with plant personnel. As discussed in the preamble in 49 FR 23530, no safety or operation problems were reported that minimal, routine maintenance would not resolve (Docket Items II-B-45, II-B-46, and II-B-47). Appropriate safety features also were evaluated by an independent consultant (Docket Item II-B-49). At the time of the 1984 proposal, the system included such features as flame arrestors; an atmospheric vent on the collecting main or gas holder to relieve excess pressure; three-way valves to lower the possibility of operator error; and steam-traced lines with drip points, condensate traps, and steam-out connections (coupled with an annual maintenance check) to reduce potential plugging problems. Since the 1984 proposal, additional features have been added such as water drains and overflow connections for tar tanks and liquid level sampling/gauging instrumentation with vapor-tight seals. Assuming each system is properly operated and maintained after installation, EPA considers that the positive-pressure system is a safe and effective control technique and that leaks (if repaired as required) do not present the fire or explosion hazard described by the commenters.

The EPA agrees that a loss of steam or electrical power for heated lines may cause naphthalene clogging in cold climates. Unless a backup power supply sufficient for the entire plant is available, EPA assumes that such a power loss would affect most plant operations and probably would result in a shutdown until power was restored. Unfortunately, EPA is aware of no other reasonable approach capable of overcoming the effects of cold climates.

Nitrogen or natural gas are two other possibilities for substitutes to coke oven gas. In fact, as described in Appendix B, the use of nitrogen was costed by EPA for blanketing benzene storage tanks because of the possibility of contamination. Factors relating to the selection of blanketing gases for particular types of sources are discussed in the preamble to the 1984 proposed standard at 49 FR 23530. The revised proposed standards do not dictate the type of blanketing gas to be used, however. Thus, nitrogen, natural gas, dirty or clean coke oven gas, or any other gas can be used as a blanketing medium for any of the affected sources.

5.3 SAFETY, DESIGN, AND OPERATION OF NEGATIVE-PRESSURE CONTROL SYSTEM

Comment: Commenters IV-D-4, IV-D-6, IV-D-7, IV-D-14 and IV-D-17 argue that, in negative-pressure systems, air infiltration resulting from ineffective sealing of older vessels, operator error, or equipment failure also creates a potential explosion or fire hazard. For example, failure to close overflow pipes during filling or pumping out of dehydrators could cause air infiltration in the collecting main. Failure of the control system when a light-oil tank car is loaded from the storage tank could cause the vacuum relief valve to function, creating an explosive atmosphere in the storage tank. Failure of both the control system and the vacuum relief valve could cause a tank to collapse while emptying or to rupture while filling, causing a light-oil spill and possibly fire. Commenter IV-D-14 also believes that use of a negative-pressure gas-blanketing system requires additional controls because of the potential explosion hazard. Specifically, the commenter states that continuous monitoring of the explosive hazard would be necessary at three or four locations in the gas distribution system. Also, an increase in oxygen concentration would require such additional measures as automatic nitrogen dilution with nitrogen or enrichment with natural gas to keep the coke-oven gas mixture below the lower explosive limit (or above the upper explosive limit).

Response: The standards (and associated costs) are based on the use of a positive-pressure system because preproposal comments questioned the safety of the negative-pressure system recommended initially. Although the use or construction of a negative-pressure system is not precluded by the regulation in any way, EPA encourages companies to install safety equipment as necessary in accordance with their historical safety policies and the system's characteristics.

Also recommended is the installation of equipment included in the costs for the positive-pressure system intended to alleviate many of the operating concerns cited by the commenters (see response to comment 5.2). For example, operator failure (on a negative-pressure system) to close overflow pipes during filling or pumping out of dehydrators can be avoided by installing an overflow pipe with a liquid seal. The potential for operator error also can be reduced by installing three-way valves so that tanks are vented at all times, either to the blanketing system or to the atmosphere.

The commenters also point to light-oil tank loading operations where a control system failure (or control system failure concurrent with failure of a vacuum-relief valve) could lead to an explosion hazard. If a storage tank is uncontrolled (i.e., open to the atmosphere) as in the current situation at most by-product plants, such a loading operation would tend to draw vapors back into the tank. If a tank is controlled by a negative-pressure system, failure of the control system would cause the vacuum-relief valve to function, permitting vapors to be drawn into the tank. Therefore, EPA considers that negative-pressure system failure under the scenario suggested by the commenters presents no more danger than similar situations encountered in the current uncontrolled plant environment. Failure of the control system implies a pressure swing within the system. Concurrent failure of a storage tank control system and vacuum-relief valves would cause vacuum-relief valves on other parts of the coke-oven gas system to function, drawing oxygen from other points. Provisions for proper operation and maintenance of relief valves are included in the standard, however, to minimize the potential for such a failure.

5.4 MONITORING FOR CARBON MONOXIDE

Comment: Commenter IV-D-14 states that overpressurization of a positive pressure system poses an explosive and occupational hazard because of the carbon monoxide (CO) released. The presence of CO increases costs for additional monitoring and employee training because CO hazards currently do not exist. Similarly, commenter IV-D-6 states that additional employees would be necessary for explosive conditions monitoring or that hydrocarbon detection monitors should be required on every (emphasis added by commenter) piece of gas-blanketed equipment.

Response: Coke plant operators have stated that pressure control in the collecting main and gas holder is inherently reliable because large pressure fluctuations can cause serious operating and safety difficulties in the operation of the coke-oven batteries and the by-product plant. Collecting main pressure is controlled by an Askania valve at a few millimeters of water pressure, and the pressure is often watched and adjusted manually if necessary. Similarly, the pressure in the gas holder is also carefully controlled. Overpressurization is prevented by bleeder or pressure relief valves and water seals.

No costs were added to the recommended gas-blanketing controls for CO monitoring because the existing and demonstrated systems, installed at other coke plants, did not have such provisions. Therefore, the monitoring question appears to be one of company policy and site-specific conditions. The revised proposed regulations would not require CO monitoring, but EPA encourages companies to follow their practice of safety reviews and implementation of precautions based on each company's historical experience, its policy, and the site's characteristics.

One additional point to consider is that a CO hazard from coke oven gas would not be unique to blanketed vessels. Coke oven gas is handled in many parts of the coke plant, which indicates that a significant portion of the facility may currently pose a CO hazard. For example, leaks of coke oven gas routinely occur around the battery proper from lids, offtakes, doors, charging, and the collecting main. Piping for coke oven gas winds through the plant, and the gas is treated in enclosed vessels such as primary coolers, direct-water coolers, and scrubbers. The gas also is piped to the battery underfiring system and is used in other parts of the steel plant. The gas-blanketed equipment is required to be enclosed and sealed and, consequently, should not be more prone to leaks than other equipment that handles coke oven gas. If a company's current policy requires detectors and monitors for every point that contains coke-oven gas, then consistent application of safety policy would require them for blanketed vessels.

5.5 SUMP CONTROLS

Comment: Two commenters (IV-D-4 and IV-D-17) believe that covering and sealing sumps create a fire or explosion hazard from concentrated fumes because no gas or steam can be used for purging. One commenter states that the purpose of leaving open sumps and trenches is to prevent such a hazard, and at his plant tramp steam is discharged routinely into sumps and trenches to reduce the possibility of fire.

Response: Two points are relevant in response to this comment: (1) steam purging increases emissions of and exposure to hazardous organic compounds, and (2) alternatives exist to detect and correct hazardous conditions.

Steam purging strips organic compounds from the sump and can be especially efficient at removing volatile compounds such as benzene. Most sumps are installed below grade; consequently, workers and others in the plant can be exposed to locally high concentrations of these organic compounds at ground level from an uncontrolled sump, especially with a purge gas.

The current practice of discharging tramp steam to an open sump already poses a hazard if concentrations are high enough to be explosive. In addition, the steam purging may create the movement of explosive vapor from the sump to ground level if a surge or slug of organic material accidentally entered the sump during purging. The EPA's costs include an air-tight seal and a vent to the atmosphere for safety. The operator may choose other measures to increase safety, such as including a flame arrestor on the vent or installing detectors for explosive conditions. Other alternatives are replacing the sump with an above-grade closed tank that may be easier to keep air-tight, or separating organic compounds upstream of the sump so the sump will not contain explosive gases. The solution to the commenter's question will depend on each site's specific conditions and each company's policy.

5.6 OPERATIONAL PROBLEM FROM PLUGGED VENTS OR VALVES

Comment: Commenter IV-D-17 suggests that mechanical vents and pressure relief valves may be fouled easily, resulting in ruptured tanks. The commenter adds that many ruptured tanks occur as the result of plugged valves that were supposed to relieve pressures.

Response: The EPA recognizes that plugged vents or valves pose an operational problem and potential safety hazard if not repaired. For this reason, the revised proposed regulation requires an annual maintenance check for abnormalities such as plugs, sticking valves, and clogged or improperly operating condensate traps. A first attempt at repair of any defect must be made within 5 days, with any necessary repairs made within 15 days of inspection. The regulation requires that records containing a brief description of any abnormalities, the repairs made, and the dates of repair be maintained for a minimum of 2 years. Although the regulation requires a maintenance inspection only once a year, plant owners or operators may want to consider performing this maintenance check more frequently, such as in conjunction with the semiannual leak inspection.

5.7 CONTROLS FOR BENZENE STORAGE TANKS

Comment: Commenter IV-D-13 requests that EPA determine whether any benzene storage tanks at by-product plants are equipped with shingle seals. If so, the commenter recommends that the regulation require any shingle seals to be replaced with continuous seals. In support, the commenter cites the Federal Register notice of withdrawal for benzene storage tanks (49 FR 8386, March 6, 1984). The notice states in part that about 12 percent of existing benzene storage tanks in the chemical and petroleum industries have shingle seals, which are far less effective than continuous seals.

Response: The shingle and continuous seals to which the commenter refers are the seals on floating roofs in tanks. Many of the tanks in by-product plants are horizontal or an older riveted design. The EPA does not know of any benzene storage tanks with floating roofs in by-product plants. The controls EPA has analyzed for storage tanks are wash-oil scrubbers and gas blanketing. These controls are applicable to horizontal tanks and would not require major tank modification (unless a tank is in extremely poor condition). The revised proposed standard does not require control of these tanks, however.

5.8 DETERMINATION OF CONTROL EFFICIENCIES

Comment: Commenter IV-D-9 asks how efficiencies of 90, 95, and 98 percent are determined under the standard.

Response: The 90-percent control efficiency applicable to wash-oil scrubber controls is based on design calculations. A full description of the methodology and design parameters is contained in Docket Items II-B-51 and IV-J-1; a summary description is provided in Chapter 4 of the BID for the proposed standards. A 95-percent control efficiency for the tar decanter was derived by adjusting the control efficiency for enclosure and gas blanketing (98 percent) downward to account for uncontrolled emissions from the approximately 13 percent of the liquid surface of the decanter that must remain open to allow clearance for the sludge conveyor. A 98-percent control efficiency has been established for gas-blanketing systems and sealed enclosures (e.g., the light-oil sump). As discussed in the preamble to the 1984 proposed rule in 49 FR 23529, the theoretical efficiency of source enclosure with gas blanketing approaches 100 percent. However, this efficiency cannot be expected to be maintained continuously for the service life of the equipment because of the eventual deterioration of seals and sealing materials. Because deterioration of piping, seals, or sealing materials can occasionally result in leaks, engineering judgment was applied to reduce the overall control efficiency to 98 percent.

Installation of the specified equipment demonstrates compliance with the standard for these sources. In other words, these control efficiencies are assumed to be achieved if the required equipment is applied. However, design calculations and verifying test data will be needed if the owner or operator wishes to apply for permission to use an alternative means of emission limitation.

5.9 GAS BLANKETING VERSUS WASH-OIL SCRUBBERS

Comment: Commenter IV-D-14 recommends that the standards permit the use of a 90-percent efficient control device (e.g., a wash-oil scrubber) in lieu of gas blanketing on process vessels, tar storage tanks, and tar-intercepting sumps. The commenter argues that use of the wash-oil scrubber would provide essentially the same health benefit as gas blanketing. Specifically, the commenter suggests that the control efficiency of blanketing at an older plant may be lower than 98 percent because of more likely leakage and downtime, and a wash-oil scrubber may achieve higher than 90-percent control.

Response: The control efficiency of gas blanketing theoretically is 100 percent. For conservative comparisons with other controls, this efficiency has been reduced to the value of 98 percent to account for occasional leakage from seals or sealing materials. Leak detection and repair requirements are included in the gas-blanketing standards to ensure that 98 percent control or greater is maintained through proper operation and maintenance of the equipment. Thus, EPA does not expect well-designed, well-operated, and well-maintained gas-blanketing systems to achieve less than 98 percent control efficiency. Although it is acknowledged in the BID for the 1984 proposed standards (page 4-28a) that an efficiency higher than 90 percent (e.g., 95 percent or greater) theoretically may be achieved, the parameters have been developed to ensure that all plants using this technique could achieve 90 percent control continuously. Thus, at proposal, EPA considered gas blanketing compared to wash-oil scrubbing on a common basis of conservative estimates of control efficiencies. Similarly, for the revised proposal, the Agency believes that a common basis of representative, if somewhat conservative, control efficiencies should be applied. If the two control techniques are compared on this basis, wash-oil scrubbers are less effective than gas blanketing and may be more costly from a nationwide perspective.

5.10 FINAL COOLERS AND NAPHTHALENE PROCESSING

Comment: Commenter IV-D-15 requests that the standards allow use of a technology for controlling naphthalene processing and final-cooler cooling tower emissions that the commenter claims to be more effective than the tar-bottom final cooler on which the proposed standard was based. This system, recently patented by his company, eliminates cooling tower emissions through indirect heat exchangers and reduces (but does not eliminate) emissions from naphthalene processing by enclosing the separator and froth flotation units. The commenter estimates benzene emissions from the processing of naphthalene skimmings at a maximum of 20 grams (g) of benzene/Mg of coke. The commenter claims that this system achieves a 95-percent benzene emission reduction from baseline compared to 81 percent for tar-bottom final coolers and has lower capital, operating, and energy requirements than do wash-oil final coolers. According to the commenter, use of a single liquid phase (water) prevents the problem of water and oil emulsion found in wash-oil final coolers.

Commenter IV-D-9 states that the regulation is unclear regarding the use of alternatives to the proposed zero emission limit for naphthalene processing and use of the tar-bottom final cooler. The commenter's company proposes to convert an existing direct-water final cooler to a closed-loop recirculated-water final cooling system. This system would use flushing liquor to cool coke-oven gas and heat exchanger "closed-to-the-atmosphere" mode of operation. The commenter believes that this system, in conjunction with gas blanketing the tanks used to hold the flushing liquor that contains naphthalene, would comply with the zero emission limit for naphthalene processing in a cost-effective manner.

The installed cost of this system is estimated at $8 million compared to $12.5 million for the tar-bottom final-cooling system shown in the 1984 proposal BID.

Response: Both commenters are suggesting the use of alternatives to tar-bottom final coolers for reducing benzene emissions from final-cooling operations at plants. Commenter IV-D-15 proposes a system that will eliminate final-cooler cooling tower emissions, but that will allow some emissions from naphthalene processing. Commenter IV-D-9 proposes a system that eliminates final-cooler cooling tower emissions and also absorbs naphthalene in tar, thus avoiding the need for physical separation and processing of naphthalene and its attendant emissions. These comments plus cost estimates included in the comment letter of commenter IV-D-14 for tar-bottom and wash-oil final coolers led EPA to further investigate technical and cost data for final-cooler control technologies. Appendix B contains a discussion for revisions to the control cost estimates since the 1984 proposal in addition to the revised cost estimates for final cooling.

Estimated capital and operating costs were requested for the proprietary indirect cooling system proposed by commenter IV-D-15. Information also was requested on the degree to which the proprietary indirect technology had been demonstrated and limitations on its applicability. When asked about wash-oil final-cooler costs in commenter IV-D-14's letter, the commenter responded instead with capital cost estimates for two indirect cooling schemes proposed for application to an existing U.S. coke by-product plant. Technical information on various indirect cooling schemes was provided to EPA by Dravo/Still, an engineering firm that designs coke by-product plants and associated control systems.

The term "indirect" is used in two contexts when discussing final cooling. One context refers to cooling of the coke-oven gas where there is no direct contact between the cooling fluid and the coke-oven gas. In the other context, there is direct contact of the cooling fluid with the coke-oven gas, but the cooling fluid itself is cooled indirectly. Both types of indirect final cooling eliminate benzene emissions from the final-cooler cooling tower that result when direct contact water is cooled atmospherically. By the above definition, wash-oil coolers, one of the control options considered in the 1984 proposal BID as more stringent than tar-bottom final coolers, is an indirect final cooler.

All the indirect final-cooling schemes must in some way deal with naphthalene remaining in the coke-oven gas just prior to light-oil recovery. The ways in which naphthalene is condensed, absorbed, dissolved or otherwise removed from the coke-oven gas prior to or during indirect final cooling yield varied potentials for benzene emissions from further handling/processing of naphthalene-containing liquids.

The proprietary indirect cooling technology proposed by commenter IV-D-15, when used to replace a direct-water final cooler, generates a liquid stream containing naphthalene that is processed in the same way as the liquid stream from a direct-water final cooler. The commenter has suggested enclosing the froth flotation/gravity separation equipment to reduce benzene emissions, but he makes no suggestion with respect to melt pit/drying tank emission control. The commenter's proposal would reduce final-cooler benzene emissions by 70 g/Mg of coke over that required by the 1984 proposed standard, and it would reduce emissions from naphthalene-processing from 107 g/Mg of coke to 28.8 g/Mg (assuming a 90-percent efficient wash-oil scrubber could be applied to the emissions from the flotation/separation enclosure). Because the 1984 proposed standard would have required zero benzene emissions from these naphthalene-processing operations, this scheme would not comply with the proposed or revised proposed regulation. If the technology recommended by commenter IV-D-15 is applied to a plant with a tar-bottom final cooler or mixer-settler (wherein naphthalene is absorbed into the tar), then the technology would comply with the regulation as proposed in 1984.

Commenter IV-D-15 submitted information that indicated the indirect cooling technology was tested for a 13-week period using full-scale plant equipment. This pilot demonstration program yielded enough data to permit a design of full-scale installation for a plant approximately the size of Model Plant 3 in the 1984 proposal BID. As of August 1985, a full-scale installation of this technology was completed in a Canadian steel plant. The Canadian plant has an existing tar-bottom final cooler, thus eliminating the need for processing and handling of naphthalene.

However, the indirect final cooler has not yet been operated for an extended period. Capital and annualized cost estimates generated from data submitted by commenter IV-D-15 indicate that the costs for their proprietary technology are in the range of cost estimates for tar mixer-settler/tar-bottom final-cooler equipment.

The indirect final-cooling technology suggested by commenter IV-D-9 avoids physical separation and processing of naphthalene by absorbing naphthalene in tar circulated with the flushing liquor through the final cooler. Provided the tanks used to accumulate the naphthalene-containing flushing liquor are gas blanketed or closed to the atmosphere, this final-cooling scheme would be equivalent to the originally proposed gas-blanketed tar mixer-settler for naphthalene operations emission control. It would exceed the mixer-settler's performance with respect to final-cooler emissions. Information supplied by Dravo/Still indicates that this type of indirect final-cooler system is in use at the LTV Aliquippa plant (whether gas blanketing of accumulating tanks is in use is not known). The capital cost estimate provided by commenter IV-D-9 for his plant is about 70 percent higher than EPA's current estimate for a wash-oil final cooler applied to that plant size.

Dravo/Still provided information about two other potential indirect final cooling schemes. One scheme uses warm wash-oil absorption to remove naphthalene from the coke-oven gas stream in the first stage of the final cooler. The second stage of the final cooler uses water to cool the coke-oven gas. This cooling water is itself cooled in an indirect wet surface air cooler. The warm wash oil, containing naphthalene, is sent to the light-oil still equipment or to a naphthalene stripper to separate naphthalene from the wash oil. Naphthalene vapors are returned to the coke-oven gas suction main upstream of the primary coolers. This recirculation system for naphthalene leads ultimately to excess naphthalene being accumulated in the recovered tar. The warm wash-oil absorption system is in use at the Armco-Middletown plant. However, the Armco plant uses an atmospheric cooling tower for the cooling water rather than an indirect cooler. The system as described by Dravo/Still eliminates benzene emissions from both naphthalene processing and the final-cooler cooling tower. A capital cost estimate for this indirect cooling technology applied to an existing U.S. plant was provided to EPA by commenter IV-D-14. That estimate indicated the capital cost was about the same as EPA's estimate shown in this document for a wash-oil final cooler applied to that plant size.

The other indirect final-cooler scheme discussed by Dravo/Still avoids direct contact between the cooling liquid and the coke-oven gas. Indirect cooling is achieved in a cross-tube cooler with water flowing through the tubes and gas flowing outside the tubes. To prevent naphthalene fouling of the heat exchanger surface, tar is injected into the cooler on the gas side where it mixes with condensing water and keeps naphthalene in suspension. The water-tar-naphthalene mixture withdrawn from the cooler is recycled to the collecting main. As in the above system, excess naphthalene leaves the by-product plant in the recovered tar. The cooling water has not contacted the gas stream, so it may be cooled in an atmospheric cooling tower without generating benzene emissions. This system also eliminates benzene emissions from both naphthalene processing and final cooling. According to Dravo-Still, this type of indirect final cooler is in use at a Dofasco plant in Hamilton, Ontario. Commenter IV-D-14 provided a capital cost estimate for this system applied to an existing U.S. plant. That estimate indicated that the capital cost would be about 28 percent higher than the current EPA estimate for a wash-oil final cooler applied to the same plant size. One reason that the cost of this indirect final-cooler system may be higher than the one described above is that it is difficult to make use of existing plant equipment in retrofitting the latter system.

Based on the information and data presented above, all of the indirect final-cooling schemes except that of commenter IV-D-15 achieve equivalent benzene emission control for naphthalene processing and handling operations when compared to the tar-bottom final cooler or tar mixer-settler required by the proposed regulation. All of the described indirect final-cooling schemes produce greater final-cooler benzene emission reductions than would be achieved through installation of tar-bottom final coolers or tar mixer-settlers.

Based on the revised environmental, risk, and cost data, the Administrator has decided to repropose wash-oil final-cooler technology as the basis for the naphthalene-processing standard for furnace plants. Wash-oil and tar-bottom final coolers have been applied at several plants. However, any system (including the ones discussed here) that meets the zero emission limit for naphthalene processing could be used in foundry plants, and any system that meets both the zero emission limit for naphthalene processing and for final coolers (and associated cooling towers) could be used at furnace coke plants.

6. ENVIRONMENTAL IMPACTS

6.1 DATA BASE FOR ENVIRONMENTAL IMPACTS

Comment: Commenters IV-D-9 and IV-D-14 state that the health risk from by-product plants is less significant than projected at proposal because nationwide benzene emission estimates are overestimated as a result of the effect of plant closures and reduced battery capacities. One commenter estimates nationwide benzene emissions to be 21,800 Mg/yr compared to the 24,100 Mg/yr estimate in the preamble (49 FR 23525).

Response: The interim status of the estimated environmental impacts was acknowledged in the preamble to the 1984 proposed standards in 49 FR 23524. As stated, the impacts were calculated initially from a data base of 55 plants. Industry data and information from the U.S. Department of Energy (DOE) received prior to proposal indicated that 13 of the 55 plants had been closed. Information was not available, however, to determine whether all reported closures were permanent. Consequently, the preamble presented environmental impacts based on 42 plants and stated that the impacts and calculations in the BID would be revised following proposal.

The data base has been revised since the 1984 proposal in several respects. Information regarding permanent closures, changes in battery capacities, and changes or corrections in site-specific operating processes have been applied to reflect the industry operating status as of November 1984. These data were supplied by individual companies and by the two major industry trade associations--the American Iron and Steel Institute (AISI) and the American Coke and Coal Chemicals Institute (ACCCI). As discussed below in response to comment 6.2, adjustments to emission factors also have been made since the 1984 proposal to indicate lower emission rates from sources at plants producing foundry (or furnace and foundry) coke. These revisions have been made to account for the combination of lower light-oil yields and lower benzene concentrations for foundry coke plants compared to concentrations for furnace coke plants. For this reason, the data base also has been segregated to show separately as well as combined the environmental impacts of control options on furnace and foundry plant industry segments.

Tables A-1 and A-2 (Appendix A) reveal a potential total of 44 furnace and foundry plants with a combined operating capacity of 50.9 million Mg/yr of coke. Of the 44 plants, 30 produce furnace coke, and 14 (mainly merchant plants) produce foundry (or furnace and foundry) coke. Of the 30 furnace plants, 6 are on cold-idle as of November 1984. These plants have been identified as follows: (1) LTV Steel--Thomas, Alabama; (2) LTV Steel--E. Chicago, Indiana; (3) U.S. Steel--Fairless Hills, Pennsylvania; (4) U.S. Steel--Lorain, Ohio; (5) U.S. Steel--Fairfield, Alabama; and (6) Weirton Steel--Brown's Island, West Virginia. Also, 1 of the 14 foundry plants (Alabama By-Products--Keystone, Alabama) is on cold-idle as of November 1984 . Because information is insufficient to predict whether these temporary closures will become permanent, these seven plants have not been deleted from the data base used to estimate the environmental impacts of the revised proposed standards. The deletion of six furnace plants from the data base would reduce the operating capacity of this industry segment from about 45.8 million Mg/yr of coke to about 39.2 million Mg/yr of coke nationwide. Foundry plant operating capacity would be reduced by about 8 percent (from about 5.1 million Mg/yr to about 4.7 million Mg/yr) if the cold-idle plant were excluded from the data base for this industry segment.

Tables A-3 and A-4 (Appendix A) display the operating processes practiced at each furnace or foundry site, as reported by the individual plants (Docket Items IV-D-1 through IV-D-18). Based on these data, half (15 of 30) of the furnace plants practice naphthalene handling and processing, a major source of benzene emissions. Direct-water final coolers and tar-bottom final coolers are used at 16 and 4 furnace plants, respectively; 5 furnace plants use wash-oil final coolers. Although tar recovery sources (e.g., tar decanters, dewatering, sumps, and storage) are found at all 30 sites, as are most light-oil plant sources (light-oil decanters, sumps, storage, and wash-oil circulation tanks), BTX storage is practiced at only 10 sites, and benzene is stored only at 4 sites.

Table A-4 indicates that naphthalene handling and processing also is practiced at half (7) of the 14 foundry plant sites. Reported data show direct-water final coolers at seven plants, tar-bottom final coolers at two plants, and no wash-oil final coolers in use. Although tar recovery sources are present at each site, light-oil storage is found at 9 of the 14 sites. Benzene and BTX are stored at one plant.

Tables 7-1 through 7-6 of the BID for the 1984 proposed standards have been revised to show the updated estimated environmental impacts. These tables display the estimated baseline nationwide benzene emissions and process capacity data for sources at the 30 furnace plants, the 14 foundry plants, and the total industry combined. Comparable data for total VOC emissions (benzene and other VOC) also are shown. Based on these data, estimated nationwide benzene emissions from the industry total nearly 26,000 Mg/yr; VOC emissions are about 171,000 Mg/yr.

The effects control options have on reducing benzene and total VOC emissions also are shown in Appendix A. Implementing the revised proposed standards would reduce overall benzene emissions from furnace and foundry coke producers from approximately 26,000 Mg/yr to about 2,000 Mg/yr, a reduction of about 93 percent. Nationwide VOC emissions also from these sources would be reduced from approximately 171,000 Mg/yr to about 6,000 Mg/yr.

The revised data base and foundry plant emission factors have little effect on the impacts or benefits of other environmental considerations associated with the final standards, such as energy requirements, water pollution, solid waste disposal, and noise or odor levels. As discussed in the preamble to the 1984 proposal notice (49 FR 23525), a nominal increase in electrical or steam requirements at furnace plants could occur if gas blanketing piping were heated to prevent vapors from condensing or freezing in vent lines. Tables A-11 and A-12 show energy use and coke-oven gas recovery estimates for model furnace and foundry plants.

Although no water pollution problems are associated with recycling benzene vapors, implementing the revised proposed standards could result in an increased HCN concentration at plants using indirect final cooling.

As discussed in the BID for the 1984 proposed standards (page 7-7), HCN is emitted currently from the final-cooler cooling tower at some plants by air stripping of wastewater. Measured HCN air emissions and calculations based on once-through cooling water indicate that about 200 g/Mg of coke could be added to wastewater for treatment, if indirect cooling rather than direct cooling were used (Docket Item II-B-30). The actual amount of additional HCN in the wastewater could depend on cooling water temperature, degree of recycle practiced, and numerous other factors.

As suggested by the commenters, the effects of reduced operating capacities and revised emission factors have been taken into account in the updated risk assessment. Further information regarding the calculation of revised emission estimates for furnace and foundry plants is discussed below in response to comment 6.2.

6.2 FOUNDRY PLANT EMISSION FACTORS

Comment: Commenters IV-D-6, IV-D-7, IV-D-10, IV-D-11, and IV-D-12 claim that operating dissimilarities result in fewer emissions compared to emissions from furnace coke plants. The commenters state that foundry plants generate fewer emissions because of: (1) the use of less volatile coal in their feed (21 to 22 percent volatile matter in foundry blends versus 28 to 30 percent volatile matter in furnace coal blends), and (2) the use of longer coking cycles (28 to 30 hours for foundry coke versus 14 to 16 hours for furnace coke). In support, one commenter also states that the percentage of benzene in light oil at his plant is 55 to 60 percent, considerably less than the 70-percent example shown in Table 3-6 of the BID for the 1984 proposed standards. Another commenter maintains that merchant plants generate fewer emissions than furnace plants not only because of different operating practices but also because of the relative size of the industry segment compared to furnace coke plants.

Response: In response to the public comments received on this issue, EPA has reviewed available information and data to determine whether the development of separate emission factors for foundry and furnace coke production is warranted. Based on results of this review, EPA agrees with the commenters' contention that benzene emissions from a foundry coke by-product plant would be expected to be less than the emissions from a furnace coke by-product plant of similar capacity. Because no emission measurements were performed in foundry coke plants during the 1979 to 1980 sampling survey, appropriate emission factor adjustments have been made based on available data for light-oil yields.

Foundry coke is produced from a coal mixture that generally contains less volatile matter than the mixtures used to produce furnace coke. The ACCCI comments suggest that typical furnace-coke coal mixes contain 28 to 30 percent volatile matter and foundry-coke coal mixes contain 21 to 22 percent volatile matter. This statement is confirmed, in part, by data contained in one primary reference source on the coking of high- and low-volatile coals (Docket Item IV-J-5) that show light-oil yields as significantly lower (less than half) for the low-volatile coals. However, definitive data on light-oil yields published by the DOE show that, over a 4-year period, the light-oil yields in merchant coke by-product plants (mostly foundry coke producers) averaged about 66 percent of those in furnace plants on a per-ton-of-coal-charged basis (Docket Items II-I-43, II-I-50, IV-J-2, IV-J-3, and IV-J-4). These yields are shown in Table A-13 of Appendix A. Table A-13 also provides data on the relative yields of tar and coke-oven gas in merchant coke plants compared to furnace coke plants. The data displayed in Table A-13 represent the principal basis for the technique used to adjust the proposed emission factors for foundry coke producers.

Based on a review of data contained in another coke-making reference source (Docket Item II-I-2), EPA also agrees with commenters who suggest that the lower coking temperatures associated with foundry coke production compared to furnace coke production (for the same coal) would lead to production of less by-product benzene. In support, one merchant plant commenter indicated that the light oil from foundry coking contains 55 to 60 percent benzene compared to the 70 percent assumed in the 1984 proposal BID (Docket Item IV-D-7). Based on an informal poll of some member companies, ACCCI provided an average estimate of 63.5 percent for foundry producers (Docket Item IV-D-7). For furnace coke production, however, a benzene content for light oil of 70 percent is still considered appropriate.

Separate emission factors for foundry plant sources have been developed by applying correction factors to the emission factors initially proposed for both furnace and foundry plants. These changes do not affect the revised emission factors as applied to furnace plants. The computations of correction factors are shown in Table A-14 of Appendix A; the final emission factors for furnace and foundry plants are shown in Table A-15.

For plants that produce only foundry coke, benzene emission factors for light-oil recovery plant sources (i.e., wash-oil decanters, wash-oil circulation tanks, light-oil condensers, and light-oil sumps) have been adjusted by a correction factor of 0.54. This adjustment factor combines the effects of lower light-oil yields, lower benzene concentrations in the light oil, and different coal-to-coke ratios. Physically, the reduced emission estimates may be viewed as a result of lower benzene throughput in the foundry coke by-product plants.

For sources treating or handling water that has contacted the coke oven gas (i.e., flushing liquor circulation tank, excess ammonia-liquor storage tank, direct-water final-cooler cooling tower, tar-bottom final-cooler cooling tower, and naphthalene handling/processing), benzene emissions are expected to be proportional to the ratio of benzene in the coke oven gas (i.e., partial pressure and partitioning between the liquid and gas). The light-oil-to-coke-oven-gas ratios in Table A-14 are indicative of the partitioning. These ratios are multiplied by relative benzene concentrations in the light oil to yield a correction factor of 0.73 for the above sources in foundry coke plants.

Emissions from storing or processing liquids containing tar (i.e., tar decanters, tar-intercepting sumps, tar storage tanks, and tar-dewatering tanks) also are expected to be proportional to the ratio of benzene in coke oven gas. In addition, the relative yield of tar (i.e., the amount of tar exposed to the benzene) is expected to affect the partitioning of benzene between the tar and the gas. Therefore, the correction factor applied reflects both the relative quantity of benzene produced, and the proportion of that benzene transferred to the tar, ultimately available for dissolution in the sources. Combining the tar yield, light-oil-in-gas ratio, benzene concentration in light oil, and coal-to-coke ratio factors has produced a correction factor of 0.47 for the above source emissions in foundry coke plants.

Equipment leaks from fugitive emission sources (i.e., pumps, valves, exhausters, sampling connection systems, open-ended valves and lines, and flanges or other connectors in benzene service) are expected to emit benzene emissions proportional to the benzene concentration in the fluids handled. The correction factor applied to emission estimates for foundry coke plants is based on the estimated benzene content of the light oil at a foundry coke plant. When the estimate supplied by ACCCI is used, the correction factor is 0.91. Table A-15 indicates the revised uncontrolled emission factors for furnace and foundry plants. Table A-16 shows the derivation of revised foundry plant benzene fugitive emission rates from VOC emission factors.

Emission estimates incorporating revised foundry plant emission factors and other data base revisions are discussed above in response to comment 6.1. The revised emission estimates were incorporated into the estimated impacts on which the selection of the revised proposed standard is based. The selection of the revised proposed standard is discussed in the Federal Register preamble for the revised proposal.

6.3 MODEL COKE PLANTS

Comment: Commenter IV-D-4 argues that benzene emission estimates for model coke plants are not representative of emissions from an actual small plant (coke capacity of 440 Mg/day). The commenter estimates uncontrolled emissions from a medium-sized model plant (4,000 Mg/day of coke) at 1,080 Mg/yr; with the 1984 proposed controls (and assuming 89 percent recovery), remaining uncontrolled emissions of 120 Mg/yr would result. This estimate excludes certain emission sources (e.g., direct-water or tar-bottom final-cooler tower, tar-dewatering tanks, and benzene or BTX storage tanks). The commenter compares 120 Mg/yr to 70 Mg/yr (uncontrolled) for the small plant. In summary, the commenter argues that small merchant plants should not be regulated because of the low emission level.

Response: In essence, the commenter argues that small merchant plants should not be regulated because of the low benzene emission levels compared to estimated emissions from medium-sized model plants. In support, the commenter suggests that his calculations show uncontrolled emissions at his plant site as less than emissions after control at a larger site. The EPA believes that the commenter has misconstrued the purpose of model plants and their role in the EPA decisionmaking process. First, EPA's decision to regulate is not based on model plant emission estimates and their level compared to larger model facilities. The EPA's decision regarding to what level to control foundry plants is discussed further in the preamble to the revised proposed standard.

The purpose of constructing model plants is to portray typical facilities in terms of size and processes representative of the industry. However, the nationwide emission estimates have been based on site-specific process data rather than by model plant extrapolation. In the preproposal analysis, model plant size parameters were selected based on the approximate distribution of actual plant capacities as a function of coke capacity. This distribution indicated that 25 of 55 plants produce between 300 and 2,000 Mg/day of coke, accounting for 17 percent of domestic capacity. Consequently, a small model plant was defined as a facility producing 1,000 Mg/day of coke, slightly less than the midpoint of the actual range.

The industry operating data updated after proposal indicate foundry plant capacities at existing sites ranging from 130,000 to 617,000 Mg/yr. The commenter says his plant's capacity is 440 Mg/day. When converted to an annual basis (approximately 161,000 Mg/yr), the commenter's plant remains well within this size range. The EPA considers that the Model Plant 1 (small) size range remains representative of small plant operations. In terms of actual onsite processes, further discussions with the commenter revealed that the commenter's plant does operate a direct-water final cooler (the commenter's statements indicated that no direct-water final cooler was present at the plant). Also present are a light-oil plant, fugitive emission sources, and most tar separation vessels. Benzene and BTX storage are not practiced. Again, although the process parameters identified with Model Plant 1 may not reflect all actual operations at the commenter's site, they typify small plant processes on the whole.

Other changes to the data base also have been made since the 1984 proposal to reflect more closely foundry plant operations. These changes include lower emission factors and recovery credits. The EPA believes that these adjustments better reflect differences between furnace and foundry plants. The changes would tend to lower the site-specific estimate suggested by the commenter. However, the inclusion of a direct-water final cooler also would need to be considered by the commenter when recalculating actual benzene emission estimates for this site.

6.4 EMISSION FACTORS FOR TAR-RELATED SOURCES

Comment: Commenters IV-D-7, IV-D-10, and IV-D-12 question the data base used to estimate emission factors and their resulting industry wide applicability for tar decanters, tar dewatering, and flushing liquor circulation tanks.

Response: The commenters argue, in essence, that test data for certain sources are not sufficient to take into account variance in emissions because of differences in the methods of operation and other factors. The EPA certainly agrees that differences in methods of operation, operating parameters, and design features are evident from plant to plant and will influence actual emissions from each source. During development of the estimated emission factors, these variations have been taken into account to the extent possible by averaging applicable measurements to obtain a factor representative of a "typical" source. Also, the emission factors have been adjusted since the 1984 proposal for improved applicability to plants producing foundry coke.

Specifically, the commenters state that data (12 tests) supporting the tar-decanter emission factor are not sufficient for industry wide application because emissions are sensitive to variability in gas-liquid separator residence time and optional heating. As discussed in Chapter 3 of the BID for the 1984 proposed standards (page 3-10), typical residence times are about 10 minutes for liquor and about 40 hours for tar. Optional heating tends to increase the total benzene emitted even though the concentration of benzene per unit volume of emissions may be reduced. The degree of separation achieved is highly variable because of coal type and differences between plants. As stated above, adjustments have been made since the 1984 proposal to account for differences between furnace and foundry plants.

The tar-decanter emission factor (applicable to furnace plants) is based on three measurements for each of four vents (12 total) at two tar decanters at two plants (Bethlehem Steel--Burns Harbor, Indiana, and Bethlehem Steel--Bethlehem, Pennsylvania). The tests spanned a flow rate range of 50 to 275 std ft^3/min. The benzene emission rate measured at the Pennsylvania steel plant was 1.2 kg/hr (Docket Item II-A-22). This decanter was one of two for a coke battery. Emissions from the two decanters were assumed to be twice the emissions from the single decanter, or 2.4 kg/hr. The corresponding benzene emission factor for this decanter was calculated as 84.7 g/Mg coke. One of three tar decanters was tested at the steel plant in Indiana (Docket Item II-A-26), where the average benzene emission rate from three vents on the decanter was 4.4 kg/hr. The corresponding emissions for three decanters at this Indiana plant are 13.3 kg/hr, which yields a benzene emission factor of 69.6 g/Mg of coke. The average benzene emission factor from these two plants was 77.2 g/Mg of coke. Consequently, the emission factor was designated as 77 g of benzene/Mg of coke. The EPA considers this data base of 12 measurements adequate to estimate the average level of emissions from typical decanter vessels under varying conditions.

The commenters also maintain that the tar-dewatering emission factor should not be applied industry wide because emissions depend on the method of operation. In support, the commenters point to the "unexplained" variations in the range of emission factors for this source (9.5 to 41 g/Mg of coke).

Emissions from tar-dewatering tanks were evaluated at three plants (see Docket Items II-A-26, II-A-27, and II-A-28). Three measurements were made for each of two vents at one plant; one measurement was made at the second plant. At the third plant, one test was made at the tar storage tank where dewatering was performed. The EPA considers that these measurements, as averaged, are sufficient to provide a reasonable estimate of emissions from a typical source.

The extent and effect of the variation in dewatering emission factors have been discussed in the BID for the 1984 proposed standards (page 3-16), which states as follows:

The emissions data for tar dewatering at the first plant showed higher emissions from the west tank (3.2 kg/hr) than from the east tank (1.1 kg/hr). These tanks are operated in series rather than in parallel, and the wet tar enters the west tar dehydrator first. Consequently, the emissions from the west tar dehydrator are expected to be higher than emissions from the east tar dehydrator. The daily benzene emission rates from the two tar-dewatering tanks at this first plant were 27 and 76 kg, respectively. Daily benzene emissions from tar dewatering at the second plant were 43 kg. The tar is dewatered in storage at the third plant, where benzene emissions were 24 kg/day. The benzene emission factors from these three plants were 41, 9.5, and 12.9 g/Mg of coke, respectively. These were averaged to obtain a benzene emission factor for tar dewatering of 21 g/Mg of coke.

The tar-dewatering tanks contained tar with 200 to 2,000 ppm benzene in the liquid. Tar, as collected from the flushing liquor and the primary cooler, can contain greater than 0.2 percent benzene or 2,000 ppm at a rate of 40 kg/Mg of coke produced. The maximum potential for benzene loss from tar dewatering and storage calculated from these values is greater than 2,000 ppm at a rate of 40 kg/Mg of coke produced. The maximum potential for benzene loss from tar dewatering and storage calculated from these values is greater than 80 g/Mg of coke. The benzene emissions from tar dewatering and storage probably will be less than 80 g/Mg of coke and will depend on the method of operating these processes.

The commenters also question the adequacy of test data from the primary cooler condensate tank as the basis for the flushing liquor circulation tank emission factor and its resulting applicability industry-wide. The emission factor for the flushing liquor circulation tank (9 g/Mg of coke) was obtained from one test in which emissions from a primary cooler condensate tank were measured (Docket Item II-A-13). This tank was assumed to be similar to a flushing liquor circulation tank because both vessels function to hold liquor taken from the gas stream during early stages of gas processing. Although it is desirable to have more than one test measurement as the basis of the estimated factor, engineering judgment suggests that the measurement is a reasonable value for emissions from flushing liquor circulation tanks. The EPA agrees with the commenter, however, that emissions will vary necessarily depending on the number and geometry of tanks, the number of vents, and other factors.

6.5 METHODOLOGY FOR EMISSION FACTORS

Comment: Commenter IV-D-33 contends that the EPA VOC and benzene emission factors are not applicable to the sources at his site and also that VOC emissions should be calculated using a different methodology.

Response: The EPA developed emission factors to obtain an estimate of the nationwide emissions of benzene and VOC from by-product plant process operations. The EPA is aware that site-specific factors could cause the actual emissions from a particular facility to vary from the estimates based on EPA emission factors. In fact, the commenter's estimate of benzene and VOC emissions from his facility using his alternate set of emission factors is within 20 to 30 percent of the emissions estimated when using EPA emission factors. This difference is within the range of uncertainty for the emission factors.

The commenter also proposed an alternate methodology for developing VOC emission factors using EPA test data that would, in general, would tend to make them lower. The commenter states that EPA overestimates VOC emissions by assuming that all components of light oil will volatilize to the same extent as benzene. The EPA agrees that this may lead to an overestimate of VOC emissions; however, the EPA believes the commenter's approach underestimates VOC because not all components of the light-oil vapor were explicitly measured in the test program whose results were used to develop the VOC emission factors. In any case, the cumulative difference between emissions estimates for the commenter's plant using the commenter's methodology were shown to be within the range of uncertainty for the emission factors, as noted above.

6.6 VOC BENEFITS FOR OZONE REDUCTION

Comment: Commenter IV-D-2 supports the proposed standard for by-product plants, particularly when applied to a plant site located in his State. This commenter believes that the estimated emission reductions are realistic and provide the added benefit of helping his State reduce the VOC inventory in the Baltimore ozone nonattainment area.

Response: The EPA thanks the commenter for his support. The estimated VOC emission reductions also will benefit the country as a whole in reducing ozone formation.

7. COST IMPACT

7.1 REVISIONS TO COST ANALYSIS

Comment: Commenters IV-D-9 and IV-D-14 argue that the capital costs of the proposed equipment are $50 million to $100 million or more, compared to the estimated cost of $23.8 million. According to these commenters, the true costs exceed model plant estimates by 50 to 100 percent at some facilities. In support, the commenters cite the following major factors contributing to 1984 EPA estimates: (1) low estimates of unit material costs and construction expenses, (2) site-specific factors such as equipment conditions and pipeline length, (3) EPA's reliance on cost-estimating references rather than experience and price quotations from local suppliers and contractors, (4) the dollar year of the estimates (1982), and (5) additional costs for work in hazardous areas requiring special safety precautions. One commenter provides for EPA review an example of these points using estimates prepared by National Steel, Armco, and by United Engineers for a Bethlehem Steel plant. Another commenter (IV-D-33 and IV-D-34) submitted information on cost estimates for controls at his plant; the commenter contends that the capital costs would be higher than the model unit costs in the 1984 proposal BID.

Response: To consider the commenters' concerns, EPA conducted a detailed review of the United Engineers' estimate for the Bethlehem plant of Bethlehem Steel, Bethlehem Steel's estimate for their Sparrows Point plant, and the Armco and National Steel cost data; EPA also had a cost estimate prepared by C. R. S. Sirrine, Inc., a third-party design engineering firm. The details of EPA's final analysis are shown in Appendix B. Included in the review was a site visit to the Bethlehem plant to resolve questions regarding equipment locations, and the sources subject to the proposed emission controls, and to obtain examples of site-specific conditions pertinent to the development of revised unit cost factors.

As shown in Appendix B, the revised cost analysis includes higher unit costs for most materials, which affects the costs estimates for most sources. The revised unit costs were composed from the data received in the comments and the cost data developed by Sirrine. The revised analysis also includes costs for sealing all sources, installation of roofs on certain storage tanks, more pipe supports, pressure/vacuum relief valves for sealed sources, and adjustments to unit cost factors for work in hazardous areas requiring special safety precautions.

The commenters' criticism of EPA for reliance on cost-estimating references is valid. The EPA agrees that it is desirable to base cost estimates on previous experience and site-specific factors. However, in the absence of abundant experience, engineering and construction firms use those same references to develop cost estimates. Backup information requested by EPA to support the commenters' cost estimates indicated that such was the case. Also, the preference for site-specific information must be compromised somewhat when attempting to develop within schedule and budgetary restraints nationwide cost impacts for 44 plants. The EPA acknowledges that costs for particular plants may be higher or lower than EPA estimates, depending on site-specific conditions. However, the revised cost analysis addresses concerns cited by the commenters and the costs are reasonable estimates of the industry wide cost of controls.

Using the revised cost analysis, the nationwide capital cost of the revised proposed standards is approximately $84 million (1984 dollars), compared to estimated capital costs of about $24 million (1982 dollars) at proposal in 1984. Of the $84 million, approximately half is due to the inclusion of wash-oil final coolers, the cost of which was not reflected in the 1984 proposal estimate.

7.2 REVISIONS TO PRODUCT RECOVERY CREDITS

Comment: Commenters IV-D-6 and IV-D-14 state that the value of potential product recovery credits has been overestimated. In particular, commenter IV-D-6 states that the value of light oil for small plants is overstated. One commenter explains that the assumption that the recovered product can be used as plant fuel or sold is not valid because, when the production of coke oven gas is greater than demand for potential fuel consumption, the excess gas is flared. One commenter states that for one plant (Lackawanna) no product recovery credit can be assumed and for another plant (Bethlehem) the credit should be reduced. The excess gas is flared at Bethlehem, and Lackawanna now has no steelmaking operation creating fuel demand.

Response: The EPA essentially agrees with the commenters that the value of potential product recovery credits was overestimated in the 1984 proposal. As discussed further in response to comment 6.2, foundry plants produce less light oil than larger furnace plants do. This difference in production quantity (reflected in new emission factors for foundry plants) has been taken into account in the computation of revised fuel value and light-oil recovery credits.

In response to the commenters' concerns, a telephone survey of seven (three furnace and four foundry) plants was conducted to determine the extent of flaring excess coke-oven gases (IV-E-9). Briefly, EPA found that this flaring is not generally practiced except as a last resort. Of the five foundry plants surveyed, only one (Empire Coke) flares gas continuously. Of the remaining four foundry plants, two do not flare excess gas at all, and two plants flare only seldomly. Of the three furnace plants surveyed, one plant never flares, one plant flares only in emergency situations, and one plant flares occasionally in periods of low demand. Consequently, the adjusted credits have been applied to most, but not all, plants. No fuel credits were applied to the Lackawanna plant of Bethlehem Steel and Empire Coke for the reasons cited by the commenters.

The value of potential product recovery credits also has been adjusted since that time to reflect 1983 data published by the DOE (Docket Item IV-J-4). Based on these data (Table A-11), the credit for light oil has been decreased from $0.33/kg to $0.27/kg light oil. The fuel value recovery credit for coke oven gas also has been adjusted downwards--$0.14/kg coke oven gas compared to $0.15/kg estimated in the 1984 proposal.

7.3 ECONOMIES OF SCALE FOR SMALL PLANTS

Comment: Commenters IV-D-4, IV-D-6, IV-D-7, and IV-D-17 maintain that small plants should not be regulated because of the disproportionate cost impact resulting from the lack of economies of scale compared to moderate or large plants, coupled with higher per-unit control costs. One commenter notes that, although control costs for small plants are the same as for medium-sized plants, the costs in relation to production are 200 to 400 percent higher; another commenter indicates that small plant costs are 900 percent higher than for medium-sized plant costs. The commenters point to the use of a cost model based on a moderate to large plant with a number of economies of scale in terms of the number of control units per ton of production. According to one commenter, this is reflected in Section 8.1.5 of the BID for the 1984 proposed standards, where actual costs are compared to estimated costs for two large plants with economies of scale.

Response: As described in the response to comment 7.1 and Appendix B, the capital and annualized cost estimates for control of benzene emissions have been revised. The basis for estimating these revised costs are the three original model plants, sized at 1,000, 4,000, and 9,000 Mg/day of coke. New capital and annualized costs of control were estimated for these plants, then cost functions (equations relating cost to plant production capacity) were developed for each process. These cost functions do provide for economies of scale, and they adequately represent the costs of control from the smallest foundry coke by-product plant to the largest furnace coke by-product plant.

8. ECONOMIC IMPACT

8.1 REGULATORY BASELINE

Comment: Commenters IV-D-6 and IV-D-7 state that the economic analysis for the proposed standards fails to consider the true state of the coking industry at baseline and that the economic impact will have an adverse effect on the industry. In support, one commenter notes that the analysis does not take into account the plant closures and capacity reductions that have occurred since 1980. Both commenters also note that the baseline does not include the cost of other environmental regulations incurred by 1983. New regulations include final iron and steel effluent guidelines, National Pollutant Discharge Elimination System (NPDES) permit upgrading, State implementation plan (SIP) compliance rules (including reasonably available control technology [RACT], lowest achievable emission rate [LAER], and new source review of coke plant rebuilding), and the pending coke-oven battery NESHAP.

Response: At the time the original analysis was conducted, the information from published and unpublished sources was current. A reanalysis has been conducted (see Appendix C) that utilizes data on plants and capacity in existence in November 1984. Financial data and production data used in baseline estimates are from the available published and unpublished sources as of 1984. A discussion of industry trends as of 1984 is provided in Section C.1.6 of Appendix C.

The baseline of the reanalysis assumes companies meet regulations existing in 1984, including OSHA rules for coke oven emissions; State regulations related to desulfurization, pushing, coal handling, coke handling, quench tower, and battery stack controls; and Best Practicable Technology (BPT) and Best Available Technology (BAT) water regulations. All of these were due to be in effect by 1983 at the latest. Other regulations that are pending or have not reached the deadline date for compliance are not likely to be a part of 1984 production costs for firms, or they will have little effect on those costs.

8.2 SELECTION OF DOLLAR YEAR

Comment: Commenter IV-D-7 suggests that the economic impact analysis should be in 1986 dollars because the project schedule places promulgation closer to regulation in 1986.

Response: Selection of the year for dollar values in analysis is somewhat irrelevant because conversions may be made for any current or past year based on gross national product (GNP) implicit price deflators. The important values are the baseline data from which regulatory impacts are determined. For these values, current information (in 1984 dollars) was used to produce realistic results in the reanalysis.

Projection to future year-dollars is difficult primarily because of the confounding effects of inflation. Prediction of inflation rates is beyond the scope of this analysis. The 1984 dollar values in the reanalysis are best updated for future timeframes when those years are current so that GNP implicit price deflators accounting for actual inflation may be used.

8.3 POTENTIAL ECONOMIC IMPACT

Comment: Commenter IV-D-14 states that the economic impacts of the proposed standards are more severe than estimated and will have an adverse economic impact on the industry. In support, the commenter cites examples from a recent Price Waterhouse "Steel Segment" survey for the period 1979 through the third quarter of 1983 to illustrate the overall financial condition of steel companies. The following major factors are cited: (1) the steel industry is depressed and suffers capital formation problems; (2) the period analyzed shows a rising debt-to-equity ratio, with declining stockholder equity; (3) investment exceeded cash from operations; and (4) the industry experienced $6 billion in losses between 1982 and 1983.

Response: The measure of severity of impacts is best made relative to some reference value rather than from the standpoint of absolute values. In the reanalysis, capital costs of compliance are compared to average annual net investment averaged over the period from 1979 to 1983 (converted to 1984 dollars) for individual companies. Table C-25 in Appendix C of this document shows these comparisons for furnace coke. For furnace coke plants, capital costs of compliance for Regulatory Alternative II range from 0 to 3 percent of net investments. For Regulatory Alternative III, these costs range from 0 to 5 percent of net investments. The regulatory alternatives are outlined in Table C-1 of Appendix C.

The industry trends noted by the commenter are discussed in Section C.1.6 of Appendix C. Companies have made adjustments through mergers, acquisitions, and creative financing measures to generate investment funds. The fact that, as the commenter states, investment exceeded cash from operations indicates that capital is available for investment even for firms sustaining losses.

Although the industry is having some capital difficulty, the burden of regulation will differ from firm to firm. The net investment analysis indicates that in no case will the cost of regulations be a significant burden.

8.4 ESTIMATED EMPLOYMENT IMPACT

Comment: Commenter IV-D-7 questions the estimated employment impacts of the proposed standards. The commenter suggests that the estimates should include total plant employment because by-product plants cannot be separated. This commenter employs 36 people in his by-product operation, but he employs a total of 268 persons in his coke plant.

Response: The commenter's argument is answered in Tables C-23 and C-28 in Appendix C, which show the employment effects of the regulatory alternatives in the furnace and foundry coke plants, respectively. These are industry totals. For the furnace coke sector, neither regulatory alternative results in a loss of more than 0.5 percent of baseline jobs at furnace coke plants for the entire industry. This is not a substantial loss, and it should be weighed against the benefits.

For the foundry coke sector, employment impacts are calculated for two scenarios. Scenario A assumes that foundry coke producers do not compete with imports in the domestic market, and Scenario B assumes they do. Under Scenario A, the regulatory alternatives result in job losses that are less than 1.0 percent of baseline foundry coke employment. Under Scenario B, employment losses for the industry are less than 3.2 percent of baseline. Again, these losses are not large.

It is possible that unemployment will not occur as a result of the regulations for two reasons. First, workers may be reallocated within the industry to perform other tasks because of labor contracts or other constraints. Second, there are potential employment gains from the regulations such as labor to operate and maintain control equipment. This labor is included in the cost analysis, but it is not evaluated in terms of added jobs. These gains may offset estimated job losses.

8.5 IMPORT TRENDS

Comment: Commenter IV-D-7 states that the regulation will increase the trend of importing coke. The commenter cites Table 9-1 of the 1984 proposal BID, which shows a growing coke-importing trend since 1974, and Table 9-2, which shows a decrease in domestic production.

Response: Data up through 1983 indicate that imports have been decreasing since 1979 (see Table C-2 in Appendix C). Trends in the steel industry away from coke-using processes and toward decreased steel production overall are the most likely sources of this decrease.

The reanalysis indicates that the regulatory alternatives result in a slight reversal of this trend. Table C-22 in Appendix C shows that furnace coke imports will increase by 9,000 Mg/yr under Regulatory Alternative II and by 25,000 Mg/yr under Regulatory Alternative III. These represent increases from the baseline of 0.23 percent and 0.64 percent, respectively. These are negligible changes in imports.

8.6 ECONOMIC IMPACT ON SMALL PLANTS

Comment: Commenter IV-D-6 maintains that the economic impact assumptions for integrated, captive producers compared to small merchant foundry plants are dissimiliar; these differences should result in separate regulations. The commenter states that "foundry producers, unlike captive producers, cannot distribute costs among operations, cannot adjust the price of coke oven gas or light-oil used elsewhere in the facility, and cannot increase the price of other by-products." The additional costs to foundry plants result in a direct increase in product price, which may give advantages to foreign competitors.

Commenter IV-D-7 argues that, for the same reasons, small plants will incur a disproportionate economic impact. This commenter also cites Table 9-40 of the economic analysis, which estimates a coke price increase ranging from 6.4 to 15.4 percent for small plants to comply with baseline.

Response: A distinction is made between furnace and foundry plants in the BID analysis and in the reanalysis for the revised proposal. Most furnace coke producers are captive, and most foundry producers are merchant. This distinction allows the analysis to examine impacts separately.

The differences between furnace and foundry producers expressed by the commenter do not necessarily result in a worsened competitive situation for foundry firms with respect to other firms in the foundry industry. In the reanalysis, no foundry batteries become uneconomic (candidates for closure) under either regulatory alternative. This implies that industry impacts of regulation will not be concentrated on any one plant sufficiently to force it out of business.

Tables C-24 and C-29 in Appendix C show the capital costs of compliance of the regulatory alternatives for furnace and foundry producers. For both regulatory alternatives, the foundry coke producers' share of total capital costs of compliance is less than 16 percent. For individual foundry coke-producing firms, Table C-30 in Appendix C shows that the capital costs of the regulatory alternatives amount to no more than 11 percent of net investment in for firms for which data were available. This is not substantially higher than the maximum share of capital costs of net investment for furnace coke producers (see Table C-25 of Appendix C). Furnace coke producers face additional pressures because of the difficulties being experienced in the steel industry, which composes the market for furnace coke.

The influence of imports in the foundry coke industry is accounted for under Scenario B of the reanalysis. A worst case bound is assumed so that quantity reductions in domestic production are assumed to be offset by quantity increases in imported coke sold domestically. The changes are 61,000 Mg/yr under Regulatory Alternative II, and 94,000 Mg/yr under

Regulatory Alternative III. These represent 2.1 percent and 3.2 percent of foundry coke demand, respectively. Advantages gained by foreign competitors because of the regulatory alternatives are small.

In the reanalysis, price impacts under Scenario A for foundry coke producers are $0.99/Mg for Regulatory Alternative II and $1.46/Mg for Regulatory Alternative III. These represent 0.58 percent and 0.86 percent increases from baseline (see Table C-27 in Appendix C). Under Scenario B, no price impacts will result. No significant impacts are projected for foundry coke producers because of these price changes.

8.7 PRICE IMPACTS

Comment: Commenter IV-D-11 states that the economic analysis is inaccurate in predicting the increased price of coke for merchant plants. This commenter estimates an increase in the price of coke at his plant of $1.38/Mg versus $0.24/Mg estimated at proposal in 1984 (49 FR 23525). This estimate is based on the commenter's estimate of the cost of compliance at his facility (capital costs of $1.8 million versus average cost of $408,500 cited in the 1984 proposal BID; annualized costs of $80,000 versus $70,500 cited in the 1984 BID). The commenter notes also that his capacity is 681 Mg/day rather than 1,362 Mg/day.

Response: The determination of changes in the price of coke must be made on a market basis rather than a plant-by-plant basis. The price changes are due to shifts in the entire supply curve, as well as the effects of the marginal plant at equilibrium for the entire market. The economic impact model uses this basis for its computation.

The reanalysis calculates capital costs of compliance, annualized compliance costs, and price changes based on capacity information available in November 1984. Capital costs of compliance for furnace and foundry plants are given in Tables C-24 and C-29 of Appendix C, respectively. Annualized compliance costs are shown in Table C-31 for furnace coke producers and Table C-32 for foundry coke producers. Tables C-21 and C-27 show price effects of the regulatory alternatives on furnace and foundry coke producers. These costs differ from engineering estimates because of the calculation of costs based on batteries with marginal cost of production at or below price, rather than all batteries.

For furnace coke, the average capital cost per plant is approximately $1.0 million for Regulatory Alternative II and $1.7 million for Regulatory Alternative III. The average annualized cost per plant is $87,500/yr for Regulatory Alternative II and $310,000/yr for Regulatory Alternative III. Price increases are $0.13/Mg (a 0.12-percent increase) for Regulatory Alternative II and $0.36/Mg (a 0.33-percent increase) for Regulatory Alternative III.

For foundry coke, the average capital cost per plant is approximately $636,000 for Regulatory Alternative II and $1.1 million for Regulatory Alternative III. Average annualized cost per plant is $118,000/yr and $264,000/yr for Regulatory Alternative II and Regulatory Alternative III, respectively. The price increase associated with Regulatory Alternative II for foundry coke is $0.99/Mg (a 0.58-percent increase from baseline), and, for Regulatory Alternative III, the price increases by $1.46/Mg (a 0.86-percent increase from baseline).

The average values may not reflect actual costs for individual plants. They serve as indicators of the neighborhood of costs a plant may be expected to face in complying with the regulatory alternatives.

8.8 ECONOMIC IMPACTS ON FOUNDRY PLANTS

Comment: Commenters IV-D-10 and IV-D-14 state that merchant plants should not be regulated because of the adverse economic impact on the 13 plants comprising this industry segment. The commenters disagree that no merchant plant will close as a result of the 1984 proposed standards. One commenter predicts the closure of three entire merchant plants because of the estimated costs of compliance. An added impact of these closures is the metal casting industry's dependence on 1.4 million tons of foundry coke production.

Response: The estimated annual compliance costs for foundry plants computed in the reanalysis are presented in Table C-32 of Appendix C, and the estimated capital compliance costs are shown in Table C-29. Average annual plant compliance costs are $118,000/yr for Regulatory Alternative II and $264,000/yr for Regulatory Alternative III. Average capital costs of compliance for foundry coke plants are $636,000 for Regulatory Alternative II and $1.1 million for Regulatory Alternative III.

In terms of net investments for companies, capital costs of compliance are relatively small. For firms for which data are available, capital costs amount to no more than 11 percent of net investment for either regulatory alternative (see Table C-30 of Appendix C). This does not imply an excessive capital burden because of the regulatory alternatives.

In the reanalysis, two scenarios for the foundry coke industry are evaluated. Under Scenario A, foundry coke producers are assumed to supply all of the domestic coke market so that supply shifts induced by the regulatory alternatives result in slightly higher prices and slightly reduced production (see Table C-27). In all cases, changes in price and quantity produced are less than 1.0 percent of baseline values.

Scenario B assumes that foundry coke producers must compete with foreign producers in the domestic coke markets. As a worst case, foreign coke is assumed to be available at a price equal to baseline, and that price is assumed to remain constant regardless of changes in the domestic market. Furthermore, imported coke is assumed to be a perfect substitute for domestic coke so that, for any reduction in domestic production, consumers will purchase amounts of imported coke equal to the reduction. Under this scenario, there is no price change because of the regulatory alternatives. The quantity changes shown in Table C-27 indicate that domestic production will decrease by 61,000 Mg/yr under Regulatory Alternative II and by 94,000 Mg/yr under Regulatory Alternative III. Import increases by these amounts reflect 2.1 percent and 3.2 percent of domestic demand, respectively.

Under either scenario, the metal casting industry is unlikely to suffer. Under Scenario A, if price and quantity changes do occur, they will not be substantial. Under Scenario B, domestic coke reductions will be offset by increased availability of imported coke.

Even if the entire shortfall in domestic production is compensated by increased imports, domestic foundry coke producers are unlikely to be significantly impacted. No closures from the regulatory alternatives are predicted under either scenario. Other impacts such as employment are unlikely to be substantial, as shown in Table C-28 of Appendix C.

9. QUANTITATIVE RISK ASSESSMENT

9.1 USE OF MODEL FOR HEALTH RISK ESTIMATES

Comment: One commenter (IV-D-14) states that EPA's prediction of the leukemia risk to the community is overstated because of the linear, nonthreshold extrapolation model. Other commenters suggest that, by mathematically predicting benzene exposures in the vicinity of the coke by-product recovery facilities and consequential risks, EPA may be estimating values that really do not exist (IV-D-6, IV-D-10, IV-D-12). These commenters suggest that EPA (1) monitor benzene near these facilities to verify the model and (2) conduct epidemiologic studies of the communities surrounding the facilities.

Response: Because a specific environmental carcinogen is likely to be responsible for at most a small fraction of a community's overall cancer incidence and because the general population is exposed to a complex mixture of potentially toxic agents, it is currently not possible to directly link actual human cancers with ambient air exposure to chemicals such as benzene. Today's epidemiologic techniques are not sensitive enough to measure the association. Direct measurement of health effects or estimation of a causal relationship to chemical exposure through community health studies usually is not possible due to the limited statistical sensitivity of such studies and the presence of a large number of potentially confounding variables (e.g., general health status, occupational exposure, smoking, diet, migration, age, etc.). Therefore, EPA must rely largely upon mathematical modeling techniques to estimate human health risks. These techniques, collectively termed "quantitative risk assessment," are the means whereby the risk of adverse health effects from exposure to benzene in the ambient environment can be estimated mathematically; effects found at higher occupational exposure levels are extrapolated to lower concentrations characteristic of human exposure in the vicinity of industrial sources of benzene. The analysis estimates the risk of cancer at various levels of exposure. A unit risk estimate for benzene is derived from the dose-response relationship observed in the occupational studies. The unit risk estimate represents the cancer risk for an individual exposed to a unit concentration of a carcinogen [e.g., 1 part per million (ppm)] for a lifetime.

Although EPA agrees that the linear, nonthreshold model is conservative in nature and would tend to provide a reasonable upper bound to the statistical range, the Agency does not agree that the assumptions upon which it is based are unreasonable or that the results of its use are exaggerated. The dose-response mathematical model with low dose linearity is used by EPA because it has the best, albeit limited, scientific basis of any of the various extrapolation models currently available. The EPA has described the scientific suppositions underlying the preference of the linear, nonthreshold model over other mathematical models (Water Criteria Documents Availability, 45 FR 79319, November 28, 1980). In this notice EPA stated:

> There is really no scientific basis for any mathematical extrapolation model which relates carcinogen exposure to cancer risks at the extremely low levels of concentration that must be dealt with in evaluating the environmental hazards. For practical reasons, such low levels of risk cannot be measured directly either using animal experiments or epidemiologic studies. We must, therefore, depend on our current understanding of the mechanisms of carcinogens for guidance as to which risk model to use. At the present time, the dominant view of the carcinogenic process involves the concept that most agents which cause cancer also cause irreversible damage to DNA. This position is reflected by the fact that a very large proportion of agents which cause cancer are also mutagenic. There is reason to expect that the quantal type of biological response that is characteristic of mutagenesis is associated with a linear non-threshold dose-response relationship. Indeed, there is substantial evidence from mutagenesis studies with both ionizing radiation and with a wide variety of chemicals that this type of dose-response relationship is also consistent with the

relatively few epidemiological studies of cancer responses to specific agents that contain enough information to make the evaluation possible (e.g., radiation-induced leukemia, breast and thyroid cancer, skin cancer induced by aflatoxin in the diet). There is also some evidence from animal experiments that is consistent with the linear non-threshold hypothesis (e.g., liver tumors induced in mice by 2-acetylaminofluorene in the large scale ED01 study at the National Center for Toxicological Research, and initiation stage of the the two-stage carcinogenesis model in the rat liver and mouse skin) (45 FR 79359).

With regard to the need for epidemiologic study of the population residing in the vicinity of the coke-oven by-product recovery plants, it must be kept in mind that current methods are not sufficiently sensitive to detect a causal association between chronic, low-level benzene exposure and cancer. Such studies are complicated by a number of potentially confounding factors. These factors include genetic diversity, population changes and mobility, lack of consolidated medical records, lack of historical benzene exposure data over each individual's lifetime, community exposure to other carcinogens besides benzene, and the latency period of cancer.

In the evaluation of benzene emissions from coke oven by-product recovery plants under Section 112 of the CAA, EPA has followed a policy in which the nature and relative magnitude of health hazards are a primary consideration. In the absence of scientific certainty, regulatory decisions must be made on the basis of the best information available. In the case of benzene, EPA has evaluated the potential adverse effects associated with human exposure based on the best scientific information currently available. For benzene, this is represented by the occupational epidemiologic studies demonstrating a causal association between exposure and leukemia.

9.2 SELECTION OF RISK MODEL

Comment: One commenter (IV-D-13) suggests that, in using HEM, and not the Industrial Source Complex (ISC) model, to estimate annual average ground level concentrations of benzene around coke-oven by-product recovery plants, EPA has underestimated exposure to the population living near those facilities. The commenter alleges that EPA has admitted the model underestimated exposure from 200 to 300 percent in the benzene fugitive emission rulemaking. Therefore, the commenter states that risk to the most exposed individuals should be much higher. On the other hand, commenter IV-D-14 states that EPA's assumption in the item that individuals are exposed to the maximum annual ground-level concentration of benzene for 24 hours/day, 365 days/year for 70 years are unrealistic assumptions that lead to exaggerated risk calculations.

Response: Commenter IV-D-13 (NRDC) raised these same concerns in a petition to the Administrator of EPA to reconsider four final benzene decisions as published in the Federal Register (49 FR 23478, June 6, 1984). The EPA responded to these concerns in EPA's response to the NRDC petition (50 FR 34144, August 23, 1985). The EPA reviewed NRDC's concerns about correcting the alleged bias in the assessment used in evaluating the benzene fugitive emission standard. In order to test the sensitivity of the regulatory decisions to changes in the exposure assessment, EPA recalculated the exposure assessment used in the benzene fugitive emission decision by increasing the ambient concentrations and, therefore, exposure by 300 percent. A factor of 300 percent was used because it is the upper limit to the alleged underestimation of exposure based on the analysis presented in Appendix C of the Benzene Fugitive Emissions Background Information for Promulgated Standards and detailed in Docket A-79-27, Item IV-B-18. After doing so, EPA concluded that the standard would not change based on the new exposure assessment. Moreover, the HEM does not always predict lower concentrations than the ISC; it is dependent on the source-specific assumptions. In addition, EPA does not know whether the ISC would be a better predictor of ambient benzene concentrations around coke by-product plants. Because of these considerations, EPA decided that this additional analysis for coke by-product plants was not warranted.

The EPA recognizes that the assumption of continuous exposure to the maximum annual concentration over a 70-year lifetime may tend to overestimate the maximum individual lifetime risk. In addition, for coke by-product plants, the assumption that the plants operate continuously at full capacity for 70 years is likely to overestimate the risk. On the other hand, some assumptions may tend to underestimate the risk. For example, there may be more susceptible subgroups than the population from which the unit risk estimate is derived. Such susceptibility can differ with infirmity, age, genetic composition, or immune-incompetancy. For these individuals, the cancer risk may be underestimated. The model assumes terrain is flat; for plants in complex terrain where the surrounding topography is at higher elevation than the emission sources, the model may possibly underestimate maximum annual concentration. Therefore, overall the Agency believes the leukemia risk estimates are plausible, if conservative.

9.3 UNIT RISK ESTIMATE

Comment: Commenter IV-D-13 contends that the benzene unit risk estimate used in the 1984 proposal has not been updated since 1981 and, therefore, did not take into consideration recently published scientific reports on benzene carcinogenicity. The commenter maintains that such an update would increase the unit risk estimate 15 times. Therefore, EPA is underestimating risk to the population residing near coke by-product recovery plants.

Response: On October 17, 1984, the commenter (NRDC) petitioned the Administrator of the EPA to reconsider four final decisions regarding benzene emissions as published in a Federal Register notice on June 6, 1984 (49 FR 23478). Of central relevance to the petition was the contention that the health risk assessment relied upon in June was outdated and that the risk estimate should be revised to reflect the most current literature on benzene carcinogenesis. The EPA agreed to a current review of the published literature and reevaluated the unit risk estimate for benzene accordingly. The methodology for the evaluating of the unit risk estimate is described in a document titled Interim Quantitative Cancer Risk Estimates Due to Inhalation of Benzene (Docket OAQPS 79-3[I], VIII-A-4) and is summarized in EPA's response to the NRDC petition (50 FR 34144, August 8, 1985). In the reevaluation of the unit risk estimate, EPA pooled the leukemia responses observed in the retrospective epidemiologic studies of rubber hydrochloride workers exposed to benzene (Rinsky et al. 1981) and chemical manufacturing workers exposed to benzene (Ott et al. 1978), then EPA computed a geometric mean of each point risk estimate. The data were aggregated to encompass a range of plausible risks observed by independent investigators of benzene exposure in different occupational settings. The leukemia incidence observed in a third epidemiologic study (Wong et al. 1983) of benzene exposure in chemical manufacturing was used as a comparison to the computed risk estimates of the pooled studies. The resulting ratio between these two sets of data was used to adjust the computed mean estimate. Based on these calculations, the unit risk estimate (the probability of an individual contracting leukemia after a lifetime exposure to a benzene concentration of one part benzene per million parts air) was revised upwards from 0.0223/ppm (6.9×10^{-6} per $\mu g/m^3$) to 0.026/ppm (8.0×10^{-6} per $\mu g/m^3$). The revised estimate represents a 17-percent increase in the estimate used in the June 1984 decisions.

The significant gap between EPA's revised risk estimate (a 17-percent increase) and the fifteenfold increase recommended by NRDC results from a major policy difference on the appropriate use of animal versus human data. The increase advocated by NRDC is obtained by relying exclusively on the incidence of preputial gland tumors of male B6C3F mice Although the results of an animal bioassays have been considered in the Agency's reevaluation, EPA believes that the unit risk estimate for inhalation of benzene is appropriately based on the principal epidemiologic studies because these studies are of recognized quality and have the greatest relevance in the estimation of health risks for the general population. Well-conducted epidemiologic studies provide direct evidence of a causal link between the chronic exposure to benzene and leukemia. This direct evidence precludes the biological uncertainties inherent in extrapolating animal data to humans. Given the wide range of levels of benzene exposures and durations of exposure, the epidemiologic studies showed a threefold to twentyfold increase in risk of leukemia above individuals not exposed to benzene. These findings present unequivocal evidence that chronic inhalation of benzene causes leukemia in humans and therefore falls within the criteria of EPA's current guidelines for carcinogen risk assessment (51 FR 33992, September 24, 1986). Although a clear dose-response association between carcinoma and benzene exposure was demonstrated in rodent bioassays, the EPA believes that human data, when available, should be the principal factor in the derivation of a unit cancer risk estimate. In the case of benzene, EPA believes that the animal data are appropriately used qualitatively to buttress the conclusion regarding benzene's carcinogenicity.

9.4 DERIVATION OF UNIT RISK ESTIMATE

Comment: One commenter (IV-D-14) expresses the opinion that the benzene unit risk estimate overstates the true risk by at least one order of magnitude. Moreover, a minor adjustment of 17 percent in the unit risk estimate published in the June 6, 1984, Federal Register notice as response to public comments on the listing of benzene (49 FR 23478) did not adequately respond to the criticisms made during the maleic anhydride proceeding. According to the commenter, the principal criticism not addressed concerned the inclusion of the Ott et al. 1978 study in the derivation of the unit risk estimate. The commenter maintains that the study should not have been used because the leukemia incidence was small, and there was a likelihood of exposure to other chemicals. In addition, the commenter feels that EPA inappropriately reclassified one of the deaths in the Ott study as myelogenous leukemia even though the cause of death on the death certificate was listed as pneumonia.

Response: The EPA has previously responded to these concerns in the response to public comments concerning the regulation of benzene as a hazardous air pollutant (49 FR 23478, June 6, 1984). Although EPA does not view the Ott et al. (1978) study, taken alone, as conclusive evidence of an association between low level (2 to 9 ppm) occupational exposure to benzene and leukemia, the Agency believes that this work, combined with other findings in the published benzene health literature, serves to reinforce the public health concerns regarding benzene exposure. Ott et al. observed 3 cases of leukemia in a cohort of 594 chemical workers when only 0.8 case was expected. This represents an excess risk of leukemia of 3.75. The EPA does not believe that omitting from the study the individual who suffered from leukemia but died of pneumonia would be an appropriate change. In view of the recognized causal relationship between benzene and nonlymphatic leukemias, EPA believes that a case of myelogenous leukemia such as this, if documented, should not be ignored.

The EPA does not view the extent of confounding exposures in the Ott et al. study as severe. The authors did exclude from their analysis persons known to have been exposed to levels of arsenicals, vinyl chloride, and asbestos, all of which have been associated with human cancer. This exclusion eliminated 53 persons from consideration including one leukemia victim. The remaining substances, which include the suspect carcinogen vinylidene chloride, have not been shown to be associated with a leukemia risk in either man or animals. Thus, inclusion of such exposed individuals in the cohort would not be likely to affect the target endpoint for benzene exposure (leukemia) in terms of increased risk.

9.5 COMPARATIVE RISK FROM GASOLINE MARKETING

Comment: Several commenters argue that benzene emissions from sources other than coke-oven by-product recovery plants present a greater risk to exposed populations and, therefore, should warrant the full resources of EPA (IV-D-10, IV-D-12, IV-D-17). They argue that gasoline service stations and other segments of the gasoline marketing industry present far greater risk to residents living near those facilities than do coke-oven by-product recovery plants.

Response: The EPA agrees that there are sources of benzene emissions into the ambient air other than coke oven by-product recovery plants. The EPA has evaluated many of the industrial sources of benzene (49 FR 23558, June 6, 1984). In addition, the EPA has concluded an extensive analysis of benzene and gasoline vapor emissions from the gasoline marketing industry, such as service stations, vehicle refueling operations, bulk plants, and bulk terminals. On August 19, 1987, the EPA Administrator issued a notice of proposed rulemaking to control refueling emissions from gasoline-fueled light duty vehicles, and to control the volatility of gasoline (52 FR 31162). These proposed standards will help protect the general public from the risk of cancer due to exposure to benzene, a component of gasoline vapor, and to evaporative gasoline as a whole. This proposal is estimated to reduce benzene emissions from gasoline refueling by about 90 percent from uncontrolled levels.

As described in the preamble to the revised proposed standard, the Administrator determined that control of benzene emissions from coke by-product recovery plants is warranted to protect the public health with an ample margin of safety.

9.6 COMPARATIVE RISK FROM OTHER SOURCES

Comment: A commenter (IV-D-14) states that the risk to benzene exposure from coke by-product plants does not seem high when compared to other risks that are accepted as commonplace in society. The commenter suggests that the average leukemia risk for the entire population exposed to benzene emissions from these facilities is 7×10^{-8} (or 7 in 100,000,000). Examples of commonly accepted risk were given, e.g., smoking one pack of cigarettes per day is a risk of cancer of 5×10^{-3}.

Response: The EPA does not average the maximum individual lifetime cancer risk calculations, but it assumes an aggregate of risk to the population residing within a radius of 50 km around coke by-product plants. Aggregate risk is a summation of all the risks to people estimated to be living within the 50 km radius of the facility. The aggregate risk is expressed as incidences of cancer among all of the exposed population after 70 years of continuous exposure to predicted ambient concentrations of benzene emitted from the facilities; for convenience, the total is often divided by 70 and expressed as cancer cases per year. On the other hand, maximum lifetime risk reflects the probability of contracting cancer to those individuals exposed continuously to the estimated maximum ambient air concentration of benzene for 70 years. The nationwide risk to the exposed population residing near coke by-product recovery plants due to the plant emissions has been calculated to be about 3 cases of leukemia per year. The maximum lifetime risk is estimated to be 6×10^{-3}.

The EPA does recognize that most human activities and events involve some degree of inevitable risk. However, the Administrator has judged that quantitative estimates of the risk from other activities should not be used as quantitative benchmarks for making decisions on hazardous air pollutants.

9.7 SELECTION OF BENZENE VS. POM

Comment: One commenter (IV-D-7) suggests that polycyclic organic matter (POM) compounds result in a higher health risk than benzene emissions, and that EPA has not chosen to regulate POM emissions.

Response: The Agency examined the information regarding benzene and POM as two different cases. The POM decision by EPA was based on several factors, including the great uncertainty as to the magnitude of the cancer risk to the public, the fact that many POM source categories are being controlled under programs to attain and maintain the national ambient air quality standard (NAAQS) for particulate matter, and difficulties in devising control programs for source categories not well-regulated (e.g., existing woodstoves, forest fires, and agricultural burning). The EPA concluded that a more appropriate regulatory strategy would be to regulate specific POM source categories (e.g., coke oven emissions, new woodstoves, and diesel cars and trucks).

9.8 CONSIDERATION OF OTHER HEALTH EFFECTS

Comment: Commenter IV-D-13 states that EPA's health impact analysis based on "cost-benefit" is flawed because: (1) the analysis includes only one of benzene's hazardous effects (leukemia), (2) EPA has ignored data showing public health danger greater in degree and broader in kind than included in the risk assessment, and (3) the assessment makes no attempt to account for concurrent control of other suspected carcinogens (e.g., toluene and xylenes).

Response: The EPA does recognize there are other health effects associated with human exposure to benzene. These effects are summarized in a recent review of the health literature by the Occupational Safety and Health Administration (OSHA) (52 FR 34460, September 11, 1987). The toxic effects of benzene on the hematopoietic system include not only myelogenous leukemia, but also aplastic anemia. Aplastic anemia is a rare, and often fatal, disorder characterized by cytopenia in the peripheral blood and in the bone marrow. Aplastic anemia is known to progress into leukemia, and both diseases are thought to occur as a result of a common pathogenic mechanism. Benzene has been associated with chromosomal damage in the circulating lymphocytes of exposed workers. Many cytogenetic agents are known to cause cancer in humans, e.g., vinyl chloride, arsenic, and ionizing radiation. Therefore, the chromosomal aberrations seen in workers exposed to benzene should be regarded as a serious consequence of exposure. Benzene exposure has also been causally linked with multiple myeloma, various forms of lymphoma, and other types of cancer. However, most of the observed cancers were not suitable for quantitative risk assessment because of statistical deficiencies in the observed data, i.e., the cancer incidence did not achieve statistical significance, the relative risk of the specific cancer could not be numerically quantified, or exposure only to benzene was not identified in the studies. On the other hand, the causal association between benzene exposure and leukemia is a strong statistical association, and it provides the most appropriate basis for estimating the population risk of cancer through the use of quantitative risk assessment. The EPA does recognize, however, that the exclusion of other rates of disease associated with benzene exposure may potentially underestimate the risk, but EPA resorted to using those studies having the highest degree of statistical confidence, demonstrating a strong association between leukemia and human exposure, in the derivation of an estimate of carcinogenic potency.

A commenter also pointed out that EPA's analysis of population risk from coke by-product recovery plant emissions was weakened by not including other carcinogens, e.g., toluene and xylenes, in the evaluation. The Agency has reviewed the scientific literature regarding the carcinogenicity of toluene and xylenes, and has determined that there is insufficient evidence to classify the carcinogenic potential of these compounds [Health and Environmental Effects Profile for Xylenes (o-,m-,p-), EPA Environmental Criteria and Assessment Office, Docket A-79-16, Docket Item No. IV-A-7 and Assessment of Toluene as a Potentially Toxic Air Pollutant, 49 FR 22195, Docket A-79-16, Docket Item No. IV-I-4]. The EPA has reasonably good data characterizing the magnitude of benzene emissions from the source category. Other specific pollutants that may be carcinogenic to humans have not been evaluated in the emissions. Simultaneous exposure to several chemical carcinogens is a frequent occurrence in the environment, and EPA is committed to toxicological research in the health risks posed to exposure of complex mixtures. The ability to predict how the total mixture of toxicants may interact must be based on an understanding of the biological mechanisms involved in such interactions. With regard to toluene, EPA has reviewed and evaluated the current information on health effects, and has determined that ambient air concentrations of toluene do not pose a significant risk to public health and that it is not currently necessary to regulate toluene under the Clean Air Act (49 FR 22195, May 25, 1984). In the public notice it was made clear that EPA is aware of additional animal testing that is under way to investigate the potential carcinogenicity of toluene, and that further assessment and review of toluene will occur upon completion of these studies. The potential noncarcinogenic health effects associated with xylenes are currently under evaluation, and EPA has not yet reached a decision on this pollutant. The EPA in the reproposal of this standard is only focusing on the emission of benzene. However, EPA believes that control and reduction of benzene emissions from coke by-product recovery plants will have the added benefit of controlling and reducing other VOC's that may also be present in the emissions.

9.9 ANCILLARY COMMENTS

Comment: As an attachment to their comments on the proposed regulation, commenter IV-D-13 (NRDC) included their petition to EPA for reconsideration of four final benzene decisions. These benzene decisions were the withdrawal of proposed national emission standards for benzene storage vessels, maleic anhydride plants, and ethylbenzene/styrene plants (49 FR 23478, June 6, 1984), and the promulgation of standards for benzene fugitive emissions (49 FR 23512 June 6, 1984). To complete the record for this rulemaking, commenter IV-D-18 submitted supplemental comments on behalf of AISI. They comprise the responses to the NRDC petition that were submitted to EPA by the American Petroleum Institute (API) and the Chemical Manufacturers Association (CMA).

Response: The EPA responded to the NRDC's petition for reconsideration on August 23, 1985 (50 FR 34144). Included in that notice were EPA's responses to API's and CMA's sumittals. Therefore, EPA's response is not repeated here.

10. EQUIPMENT LEAK DETECTION AND REPAIR

10.1 DETERMINE EMISSIONS OVER BACKGROUND LEVELS

Comment: Commenter IV-D-9 asks, "What is the background level for proposed standards of 500 ppm above background?"

Response: Section 4.3.2 of Method 21 (48 FR 37598, August 18, 1983, Docket Item IV-I-1) describes the procedure for determining the presence of emissions over background levels. Accordingly, the local ambient concentration around the source (i.e., background) is determined by moving the probe inlet randomly upwind and downwind at a distance of 1 to 2 meters (m) from the source. If an interference exists with this determination because of a nearby emission or leak, the local ambient concentration may be determined at distances closer to the source [but not closer than 25 centimeters (cm)]. The probe inlet is then moved to the surface of the source to determine the concentration. (This procedure is described in Section 4.3.1 of the Method.) The difference between these concentrations determines whether there are no detectable emissions (i.e., no more than 500 ppm above background).

10.2 COMPLIANCE WITH LEAK DETECTION AND REPAIR PROGRAM

Comment: Commenter IV-D-16 recommends that the regulations state specifically that a leak (a reading over 10,000 ppm) is a violation when documented during a compliance inspection. According to the commenter, the 1984 proposed rule provides no assurance that a component is actually inspected, reported, or repaired because this information could easily be fabricated. Also, enforcement action is unlikely because EPA must prove that inspection, reporting, or recordkeeping requirements were not met. According to the commenter, only such a direct enforcement mechanism will provide incentive for diligent, reliable inspections; without this change, the commenter considers the recordkeeping and reporting provisions to be only industry "self-enforcement" rules.

Response: Sealings and packings inherently leak; only the use of leakless equipment can prevent occasional leakage. Because an occasional leak cannot be prevented without the use of leakless equipment, EPA cannot accept the commenter's suggestion that a leak (a reading over 10,000 ppm) should be considered a violation when documented during a compliance inspection. Instead, the compliance burden has been placed on the owner or operator to repair leaks as soon as possible after their detection.

The commenter asserts that enforcement is unlikely because it must be proven that recordkeeping and reporting requirements were not met or that the leaking component was not repaired. The EPA disagrees. The regulation states that compliance will be determined by review of records, reports, performance test results, or inspections. By comparing records and reports of plant performance to the actual sources during an onsite inspection, enforcement personnel will be able to detect unrepaired sources, unsubstantiated records regarding delayed repair, falsified records, and a lack of records or reports. Under these standards, the records and reports (or lack thereof) provide usable evidence of a violation, and enforcement action is likely. Although the recordkeeping and reporting requirements, coupled with onsite inspections, are the only measures to determine compliance, EPA believes these provisions are adequate to ensure diligent monitoring and repair of leaks by plant personnel and effective enforcement by EPA.

10.3 DEFINITION OF EQUIPMENT LEAK

Comment: Commenter IV-D-13 requests that EPA reconsider changing the definition of an equipment "leak" from 10,000 parts per million volume (ppmv) to 1,000 ppmv or to the highest level at which EPA can demonstrate, with data, that directed maintenance does not result in net emission reductions. The commenter remarks that emissions from equipment leaking at rates below 10,000 ppmv are substantial: about 13 percent of total emissions from pumps, 2 percent of total emissions from valves in gas service, 16 percent of emissions from valves in liquid service, and 16 percent of total emissions from compressors, according to the BID for proposed national emission standards for benzene fugitive emissions (EPA-450/3-80-032a). The commenter NRDC states that data from a study on "directed maintenance"* summarized in the BID for the proposed new source performance standards (NSPS) for equipment leaks at petroleum refineries (Docket Item II-A-43) contradict its position that a lower definition would not reduce emissions. In this study, EPA tested the performance of both undirected and directed maintenance on valves with initial leak rates less than 10,000 ppmv. The EPA found that with directed maintenance there was a net reduction of 85.2 percent emissions.

Response: The EPA's rationale for selecting the 10,000-ppmv leak definition has been discussed in the promulgation BID's for VOC fugitive emissions, in the proposal preamble for this rule, and in the rulemakings for the synthetic organic chemicals maufacturing industry (SOCMI) (Docket Item IV-A-2), petroleum refinery fugitive emissions (Docket Item IV-A-3), and benzene fugitive emissions (Docket Item IV-A-1).

The key criterion for selecting a leak definition is the mass emission reduction demonstrated to be achievable. The EPA has not concluded that a lower leak definition is demonstrated. A net increase in mass emissions might result if higher concentration levels result from attempts to repair a valve with a screening value between 1,000 and 10,000 ppmv. Although many leaks can be repaired successfully at concentrations less than 1,000 ppmv, even one valve repair failure may offset many successful valve repairs. Most data on leak repair effectiveness have applied 10,000 ppm as the leak definition and therefore do not indicate the effectiveness of repair for leak definitions between 1,000 and 10,000 ppm. Even though data between these values are available, they are not sufficient to support a leak definition below 10,000 ppm. As the commenter noted, although there is some evidence that directed maintenance is more effective, available data are insufficient to serve as a basis for requiring directed maintenance for all sources.

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*In "directed maintenance" efforts, the tightening of the packing is monitored simultaneously and is continued only to the extent that it reduces emissions. In contrast, "undirected" repair means repairs such as tightening valve packings without simultaneously monitoring the result to determine if the repair is increasing or decreasing emissions.

A leak definition is an indicator of whether a source is emitting benzene in quantities large enough to warrant repairs. Certainly, a leak definition of 10,000 ppmv accomplishes this goal. About 10 percent of all valves (leaking and nonleaking) contribute about 90 percent or more of the emissions from valves. At a leak definition of 10,000 ppmv, approximately 90 percent or more of the leaking valves would be detected, based on testing in refineries and chemical plants (Docket A-80-44, Docket Items II-A-30 and II-A-34). Most seals on pumps and exhausters leak to a certain extent while operating normally, compared to valves that generally have no leakage. When the seal wears over time, the concentration and emission rate increase. Properly designed, installed, and operated seals have low instrument meter readings, and seals that have worn out or failed have readings generally greater than 10,000 ppmv. Over 90 percent of emissions from exhauster seals and pump seals in light liquid service are from sources with instrument readings greater than or equal to 10,000 ppmv.

The EPA believes that there is only a small potential emission reduction for sources having benzene concentrations between 1,000 and 10,000 ppmv. Therefore, using a lower leak definition would not increase emission reductions significantly, even if EPA judged that repair was effective for leaks of 1,000 ppmv. In the proposal BID for the petroleum refinery fugitive emissions NSPS (Docket Item II-A-43, p. 4-8), there is a comparison of the percentage of total mass emissions affected by selecting a 10,000-ppmv leak definition over a 1,000-ppmv leak definition. These percentages represent maximum theoretical emission reductions that could be expected if the sources were instantaneously repaired to a zero leak rate and no new leaks occurred. For pump seals in liquid service and compressor seals (similar to exhausters in coke by-product plants), the estimated decrease is only 6 to 7 percent; for valves in gas service, it is only 1 percent. This small potential decrease in emissions may be offset by attempting to repair sources with low leaks.

In summary, EPA does not disagree with NRDC that additional emission reductions potentially could be achieved by reducing the leak definition from 10,000 to 1,000 ppmv. However, EPA has concluded that 10,000 ppmv is a demonstrated and effective leak definition (i.e., there are large enough emissions that repair can be accomplished with reasonable costs), but has not concluded that 1,000 ppmv is a demonstrated leak definition. Until EPA has adequate data to support the repair potential associated with leak definitions such as 1,000 ppmv, EPA is selecting the clearly demonstrated leak definition of 10,000 ppmv instead of a lower level.

10.4 ON-LINE VALVE REPAIR

Comment: Commenter IV-D-13 refers to the 1984 proposal BID discussion indicating that on-line repair of valves by drilling into the valve housing and injecting a sealing compound is growing in acceptance, especially because of safety concerns. The commenter states that this discussion means the practice has been demonstrated and should be required in the final standards.

Response: The EPA does not agree that acknowledging a promising repair method must be interpreted as meaning "demonstrated" within the context of the CAA, or that acknowledgment alone constitutes sufficient justification for a regulatory requirement. The 1984 proposal BID does state on page 4-52 that drilling into the valve housing and injecting a sealing compound is a practice "growing in acceptance" for the on-line repair of valves. Although the term "growing in acceptance" can be interpreted to mean that the practice has been reported as one repair method, the phrase also implies reluctance by plant owners and operators to use the technique. This hesitancy would be due, in part, to factors such as the type and location of the valve or the nature of the leak. For example, plant personnel may prefer to tighten the packing gland rather than drill into the housing of a critical valve containing a potentially explosive mixture. Or, as discussed in the preamble to the 1984 proposed rules (49 FR 23533), the valve (or the leak) may require removal or isolation. Also, this repair approach cannot be used on control valves or other block valves that are frequently operated because the valve would then be destroyed and must be replaced. Because of uncertainties regarding the applicability of this method to the different types of valves and varying repair conditions, this technique cannot be considered fully demonstrated at this time.

Also, the long-term practicability and cost effectiveness of this method are unknown. Depending on the valve and other factors, this approach may be no more than a temporary repair until the next unit shutdown. Without such information, the technique cannot be (and was not) evaluated as the basis of the standards and a potential regulatory requirement.

Even if the practice were fully demonstrated and its long-term practicability and costs were known and deemed superior, an ensuing regulatory requirement still might not be appropriate. The leak detection and repair program places the regulatory burden on plant owners and operators to detect and repair leaks as they occur. Unless a shutdown is required, all valves must be repaired. A repair period of 5 to 15 days has been provided to allow plant owners or operators the flexibility necessary for efficient handling of repair tasks while maintaining an effective emission reduction. To provide this flexibility, the standards do not dictate any single repair method--only the repair; delays are allowed only under limited circumstances. If any plant owner or operator chooses to apply this method, it is certainly not precluded under the standards. To require this method for all valves, however, would be premature and unwarranted.

10.5 EQUIPMENT LEAK REPAIR PERIOD

Comment: Commenter IV-D-13 recommends that the repair period for equipment leaks be 24 hours for the first attempt (rather than 5 days, as proposed), with completion within 5 days as opposed to 15 days. The commenter suggests that the shorter timeframe is adequate because monitoring personnel should be accompanied by workers prepared to fix any leak upon detection or immediately afterwards.

Response: The EPA's justification for proposing the 5-day first-attempt-at-repair interval and the 15-day repair period for pumps, valves, and exhausters was described in the preamble to the 1984 proposed rule at 49 FR 23541.

The selected repair intervals provide maximum effectiveness of the leak detection and repair program by requiring expeditious emission reduction, while allowing the owner or operator the time to maintain a reasonable overall maintenance schedule for the plant.

During development of the standards already promulgated for equipment leaks in refineries and chemical plants, EPA personnel made a concerted effort to investigate and gain knowledge of the industry maintenance practices. In EPA's technical judgment, an initial attempt at repair within 5 days is ample for all simple field repairs. A 24-hour period following leak detection is often not long enough to allow maintenance personnel to identify the cause of a leak and then to attempt repair. Although plants could schedule repair personnel to accompany the monitoring team in advance of monitoring, emergency situations or critical equipment problems could easily postpone these arrangements. Although some or perhaps even most repairs can be made within 24 hours, it is not practical to require an attempt to repair all equipment within 24 hours. The EPA has not been able to distinguish between equipment that could and could not always be repaired within 24 hours. In addition, with the commenter's approach, repair crews would spend much of their time on an inspection with few needed repairs. The costs of this approach have not been estimated by EPA because it is not practical. Furthermore, the owner or operator has an incentive to repair leaks as quickly as possible to prevent additional product losses.

A 15-day repair interval provides time for isolating leaking equipment for other than simple field repairs. A 5-day interval, as suggested by NRDC, however, could cause scheduling problems in repairing valves that are not conducive to simple field repair and that may require removal from the process for repair. A 15-day interval provides the owner or operator with enough time for determining precisely which spare parts are needed and sufficient time for reasonably scheduling repair. In addition, a 15-day repair interval allows more efficient handling of more complex repair tasks while maintaining an effective reduction in equipment leaks. Again, the owner or operator has an incentive to repair leaks promptly.

The commenter's suggestion that leaks can be detected and repaired within a shorter timeframe if repair workers accompany monitoring personnel may be helpful for plants able to make such arrangements.

10.6 DELAY OF REPAIR

Comment: Commenter IV-D-13 recommends that the proposed provisions for delay of repair beyond a unit shutdown be tightened to prevent abuses. The commenter suggests that it is possible under the proposed rules to claim lack of equipment in stock as a reason to delay when "there was in fact plenty of time to anticipate stock needs."

Response: The delay of repair provisions included in the standards is necessary to ensure technical achievability and reasonable costs. Delay of repair beyond a unit shutdown is not allowed for any types of equipment other than valves. Spare parts for valves (e.g., packing gland bolts and valve packing materials) can be stocked so all leaks that cannot be repaired without a process unit shutdown can be repaired during the shutdown. In a few instances, however, the entire valve assembly may require replacement. The standards address this situation by allowing delay of repair beyond a process unit shutdown only if the owner or operator can demonstrate that a sufficient stock of spare valve parts has been maintained and that the supplies had been depleted. If an owner or operator has sufficient time to obtain a piece of equipment, he or she could not reasonably claim a delay of repair as a result of lack of equipment.

10.7 ALTERNATIVE STANDARD FOR VALVES

Comment: Commenter IV-D-13 states that the proposed alternative performance standard for leaking valves should be 1 percent rather than 2 percent. According to the commenter, the allowance of 2 percent leaking valves will result in an average leak rate well over 1 percent. The commenter believes it inappropriate for EPA and the public to bear all the risk of statistical sampling error.

Response: The alternative standards for valves were provided for owners and operators of units exhibiting low leak frequencies because the cost effectiveness of monthly/quarterly leak detection and repair becomes unreasonable at low leak frequencies. The 2-percent limit is intended to be used as an upper limit for determining compliance with the alternative standards. If a process unit is subject to and exceeds the 2-percent limit, the unit does not comply with the standard and is subject to enforcement actions. The EPA believes that enforcement action should be taken when noncompliance is supported by the facts. Thus, because the 2-percent limit accounts for the uncertainty in setting this numerical emission limit, EPA can proceed with enforcement action clearly supported by the facts. Although there is a regulatory difference between a 2-percent and a 1-percent limit, there is no significant practical difference to either plant owners and operators or to EPA between limits of 1 percent or 2 percent of valves leaking. An owner or operator of a process unit would implement the same control measures to comply with the alternative valve standard whether the limit were set at 1 or 2 percent. The NRDC implies that the 2-percent limit is set in industry's favor; in a practical sense, however, there is little difference in terms of numbers of valves leaking when maximum limits and averages are compared. For example, a typical process unit with about 105 valves in service is allowed to have no more than 2 valves leaking out of the control at the 2-percent maximum limit. A 1-percent limit would allow no more than one valve leaking. The work practices and equipment used to achieve a rate of 2 valves leaking out of 105 valves in a process unit at any one time are the ones that would be used to achieve a 1-percent limit.

10.8 EXEMPTION FOR DIFFICULT-TO-MONITOR VALVES

Comment: Commenter IV-D-13 states that the exemption for difficult-to-monitor valves is not warranted. Valves above 2 m, according to the commenter, can be reached by a sampling probe on a boom or by a mobile "cherry picker."

Response: The EPA disagrees that the exemption for difficult-to-monitor valves is unreasonable. The intent of the standards is to monitor valves that can be reached with the portable ladders or with existing supports such as platforms and fixed ladders. A valve only may be exempted from monthly monitoring, provided: (1) the plant owner or operator demonstrates that the valve cannot be monitored without elevating monitoring personnel more than 2 m above a support surface, (2) the valve is in an existing process unit, and (3) the plant owner or operator follows a written plan requiring monitoring at least once per year.

The EPA compared the cost effectiveness of scaffolding to annual, quarterly, and monthly monitoring of difficult-to-monitor valves in petroleum refineries (see Docket Item IV-B-4). Based on this analysis, EPA found the costs of using scaffolding for annual monitoring of benzene emissions from difficult-to-monitor valves to be reasonable compared to similar costs for monthly and quarterly programs. These costs were estimated as the base cost for monitoring and maintenance for readily accessible valves plus the additional labor cost for scaffolding. No purchase cost of scaffolding was included because the plant was assumed to have purchased this equipment for maintenance. However, the previous purchase of a sampling probe on a boom or a mobile cherry picker cannot be assumed. Consequently, these purchase costs would result in even higher costs for each difficult-to-monitor valve. Some valves may be located in plant areas that are not accessible for repair work using a mobile cherry picker or a sampling probe on a boom.

Other cost and technical problems are associated with use of a mobile cherry picker or sampling probe on a boom for monitoring. In general, few leaking difficult-to-monitor valves are expected at a typical by-product plant. Although some valves may be located in groups (e.g., elevated pipe racks), others may be scattered throughout the plant. The additional labor required for driving, scheduling, and transporting the vehicle from valve to valve would further increase the costs previously discussed.

The EPA considers impractical NRDC's suggestion for use of a sampling probe on a boom because it lacks the precision necessary for effective monitoring. The monitoring team would not be able to move the probe around the leaking valve stem or as close as possible to other potential leak interfaces, as required by the standard. Considering the high cost and the technical infeasibility, EPA considers that no benefits would be achieved by this approach.

10.9 ALTERNATIVE STANDARD FOR OPEN-ENDED VALVES OR LINES

Comment: Commenter IV-D-14 suggests that an alternative standard of no detectable leaks (10,000 ppm) be considered for open-ended valves or lines in lieu of the proposed equipment requirement of a cap or plug. This alternative, coupled with monthly monitoring, would satisfy the EPA goal of leak prevention.

Response: The standards would require open-ended valves and lines to be equipped with a cap, plug, blind flange, or a second valve depending on the individual application. If a second valve is used, the upstream valve must be cleared first before the downstream valve is closed to prevent process fluid from being trapped between the valves. The standards would also allow a bleed valve or line in a double block and bleed system to remain open when the line between the two block valves is vented. The bleed valve must be capped, however, when not opened. This provision is intended to avoid plugging out-of-service bleed valves in a block and bleed system. These equipment and operational requirements will reduce uncontrolled benzene and VOC emissions from open-ended valves or lines by 100 percent.

The commenter suggests an alternative standard of no detectable leaks, with applicable leak detection and repair (LDAR) requirements. Application of a cap, plug, blind flange, or second valve is the only effective method available for reducing or eliminating emissions from open-ended valves or lines. In EPA's judgment, this equipment still would be necessary to meet the repair requirements of the LDAR program, even with a leak definition of 10,000 ppm. However, plant owners or operators would continue to bear the additional cost of monthly monitoring.

The LDAR program, with a leak definition of 10,000 ppm, should not be confused with a no detectable emission limit. Plants subject to a no detectable emission limit would be required to conduct an annual performance test for each open-ended valve and line. The plant would be out of compliance if emissions from any of the sources exceeded 500 ppm above background, as measured by Reference Method 21. Again, use of a cap, plug, blind flange, or second valve still would be needed to ensure compliance. Additional costs also should be anticipated for the recordkeeping and reporting requirements associated with performance testing.

Although this approach does not seem reasonable because it would require the same controls at additional cost, the owner or operator could apply to use this method as an alternative means of compliance with the standard.

11. RECORDKEEPING AND REPORTING

11.1 ALTERNATIVE MONITORING AND RECORDKEEPING

Comment: Commenter IV-D-9 asks if monitoring and recordkeeping requirements can be modified if a technology better than that required by the standard is used.

Response: Section 61.136 of the standards describes the procedures for obtaining EPA approval of alternative means of emission reduction that are equivalent to or better than the equipment, design, operational, or work practice standards required by the standard. Provisions are included that allow EPA to include requirements necessary to ensure proper operation and maintenance. Consequently, if an owner or operator applies for use of an alternative means of emission limitation, EPA would consider requiring monitoring, recordkeeping, and reporting requirements appropriate for the alternative on a case-by-case basis.

11.2 RETENTION PERIOD FOR RECORDS AND REPORTS

Comment: Commenter IV-D-13 argues that records and reports should be maintained permanently (or for a minimum of 5 years) because of the availability of automated data systems. If audits or inspections occur only once every 1 or 2 years, it is important to have available complete records for more than 2 years.

Response: The Office of Management and Budget (OMB) implementation of the Paperwork Reduction Act of 1980 (PL-511) specifies 3 years as a limit beyond which it becomes burdensome for plant owners and operators to keep records other than health, medical, or tax records. The EPA selected the 2-year period based on considerable enforcement experience. The 2-year limit, although less than that allowed by OMB, applies to significantly detailed plant records that would help enforcement personnel assess compliance with the standards. The EPA considers the burden associated with these records to be reasonable for the 2-year period. However, EPA does not agree with the commenter that, if EPA audits a plant less frequently than once every 1 or 2 years, EPA would not be able to ensure compliance with the standard. Once every 2 years is frequent enough to review and determine compliance for most owners or operators affected by the standard. Thus, it would not be necessary for a plant to keep records longer than 2 years. For these reasons, EPA believes that it is not necessary to require that owners and operators retain records longer than a 2-year period. Permanent retention by automated data systems was not considered necessary for effective enforcement.

11.3 ENFORCEMENT BASED ON RECORDS AND REPORTS FOR EQUIPMENT LEAKS

Comment: Commenter IV-D-13 states that the recordkeeping and reporting requirements are not strong enough for effective enforcement. In support, the commenter cites the failure of the proposed rules to require identifying tags for leaking equipment to facilitate identification of "repeat offenders" and the failure of the rules to require reporting of the specific identity of leaking equipment--only totals.

Response: Tagging is not specifically required by the standard, but the standard does require some form of weatherproof and readily visible identification that would enable plant personnel or EPA inspectors to locate leaking sources readily. Tagging is a useful method of identification that has been used in leak detection and repair programs. Any form of identification is acceptable, however, as long as it is weatherproof and readily visible. For example, a process unit may have a system of identifying markings on valves and a diagram that is available to allow easy location of the marked valves. This type of identification system works as effectively as tagging and is often used by chemical plants and petroleum refineries. To require tagging would be unnecessarily restrictive if an owner or operator can identify leaking equipment just as effectively by other means.

12. MISCELLANEOUS

12.1 ALTERNATIVE MEANS OF EMISSION LIMITATION

Comment: Commenter IV-D-14 recommends revised requirements for collection and verification of test data to demonstrate equivalence of an alternative means of emission limitation. In general, the commenter suggests permitting demonstration of equivalence based on design and engineering data, with verification after the implementation of controls. This approach would solve the timing problem encountered in collecting and verifying data before permission is granted because actual data may not be available until after controls are installed and relevant data from other facilities may not be available.

Response: The 1984 proposed regulation provided the plant owner or operator the opportunity to offer a unique approach to demonstrate the equivalency of any means of alternative emission limitation to the standard. If an owner or operator could demonstrate sufficiently the equivalency based on design and engineering data, EPA will consider that approach acceptable.

12.2 DEFINITION OF TAR DECANTER

Comment: Commenter IV-D-14 recommends a revised definition of "tar decanter." The commenter argues that EPA assumes 98-percent control efficiency on tar-intercepting sumps and 95-percent control for decanters because sumps separate light tars while decanters separate heavy tars and sludge. However, some sump units separate light and heavy tars, requiring a sludge conveyor similiar to that used by the decanter. Because of the conveyor, the sump cannot be endorsed for 98-percent control. The commenter recommends a revised definition of tar decanter to include "any vessel, tank, or other type control that functions to separate heavy tar and sludge from flushing liquor."

Response: The EPA agrees with the commenter's suggestion that the definition of "tar decanter" be clarified. In response, the revised proposed regulation contains the following definition:

> "Tar decanter" means any vessel, tank, or other type of container that functions to separate heavy tar and sludge from flushing liquor by means of gravity, heat, or chemical emulsion breakers. A tar decanter may also be known as a flushing-liquor decanter.

12.3 DEFINITION OF EXHAUSTER

Comment: Commenter IV-D-9 asks to what extent upstream and downstream of the rotors does the definition of "exhauster" extend?

Response: In response to the commenter's question, EPA has revised Section 61.131 of the proposed standards to include the following definition for "exhauster":

> "Exhauster" means a fan located between the inlet gas flange and outlet gas flange of the coke oven gas line that provides motive power for coke oven gases.

12.4 WAIVER REQUESTS

Comment: Commenter IV-D-14 recommends that the standard allow any waiver request submitted within 90 days to be granted on an interim basis until final determination is made. The commenter indicates that many waiver requests will be made and suggests that it is unlikely that all waivers can be submitted and reviewed by EPA within 90 days of the effective date. Without such a provision, operators will be in a technical state of noncompliance until the final determination can be made.

Response: The CAA clearly states in Section 112(c)(1)(B) that an existing source shall comply with the standard within 90 days of the effective date unless the source is operating under a waiver of compliance. Section 112 makes the granting of a waiver contingent upon EPA's finding "that such period is necessary for the installation of the waiver to assure that the health of persons will be protected from imminent endangerment." Granting a waiver before making these findings would be inconsistent with the statute. Thus, EPA has not included the commenter's recommendation. The owner or operator of a source should submit the waiver application as soon as practicable to allow time for the Agency to make a determination within the 90-day period after the effective date. One should note that the owner or operator should take advantage of the time between reproposal and promulgation to prepare significant portions of a plan for achieving compliance. In addition, the source should continue to take all possible steps toward achieving compliance while the Agency is evaluating the waiver application.

12.5 NEED FOR ADDITIONAL ENFORCEMENT RESOURCES

Comment: Commenter IV-D-1 requests that the proposed standard be simplified to reduce the enforcement resources needed to ensure compliance. According to this commenter, additional enforcement resources will be necessary or a reduction in enforcement activities in other areas will be required.

Response: The commenter did not describe specifically the provisions of the regulation he considers would require resource-intensive enforcement. The regulation inherently has many aspects because by-product plants comprise several sources with different applicable control techniques. However, EPA has designed the reporting requirements to be as simple as possible, while also providing enforcement personnel indications of potential noncompliance.

12.6 SELECTION OF FORMAT

Comment: Commenter IV-D-17 states that the regulations do not make clear why some requirements are expressed as equipment standards while others are expressed as emission limits. The commenter asks specifically why different standards are applied for different process sources, such as tar decanters, tar dewatering, and the naphthalene sump (e.g., naphthalene processing).

Response: The type of standard (e.g., emission, equipment, work practice, design, or operational) depends not on the function of the source, as implied by the commenter, but on the control technique selected as the basis of the standard.

Section 112 of the CAA requires that an emission standard be established unless such a standard is not feasible to prescribe or enforce. "Not feasible to prescribe or enforce" means that the pollutant cannot be emitted through a conveyance designed and constructed to emit or capture the pollutant or that measurement methodology is not practicable to apply because of technological or economic limitations. If an emission standard is not feasible to prescribe or enforce, one of the other types of standards (including any combination) can be applied.

Gas blanketing has been selected as the basis of the standards for both tar decanters and tar-dewatering vessels. In the original preamble discussion in 49 FR 23528, EPA explained why an emission standard, such as a zero emission limit, was not feasible for gas-blanketing systems. Such a standard could not be achieved on a continuous basis because, after installation of the system, vapor leaks occur occasionally because of the gradual deterioration of sealing materials, even when proper operation and maintenance procedures are applied. Fugitive emissions also may be released from openings such as access hatches and sealing ports. These fugitive emissions cannot be eliminated because the openings are necessary for proper operations and maintenance of the sources. An emission standard, it was argued, would be infeasible to prescribe or enforce not only because it could not be achieved on a continuous basis (and thus was not appropriate), but because these vapor leaks and fugitive emissions could not be emitted through a conveyance designed and operated to emit or capture the emissions. Therefore, mass emissions could not be measured. For these reasons, an equipment standard rather than an emission standard (i.e., limit) was developed for gas-blanketed sources.

The commenter also questions why different standards (e.g., zero emissions) have been established for naphthalene sumps (processing). In this case, a process modification requiring the collection of naphthalene in tar (for foundry coke plants) or wash-oil (for furnace coke plants) was selected as the basis of the revised proposed standards. Collecting naphthalene in tar (or wash oil) would eliminate naphthalene-processing operations (including naphthalene sumps) and the emissions that result from separating naphthalene from the hot well of a direct-water final cooler. Because these emissions and emission sources can be eliminated by such a modification, a zero emission limit is considered feasible to prescribe and enforce and has been selected as the format for the revised proposed standards for naphthalene-processing.

12.7 LIGHT-OIL SUMP CONTROL EFFICIENCY

Comment: Commenter IV-D-14 states that the 98-percent control efficiency assigned to light-oil sumps is unsupported and should not be used as the basis for qualifying an alternative means of emission limitation. The commenter recommends instead application of semiannual monitoring to determine that there are no detectable emissions.

Response: The 98-percent control efficiency assigned to light-oil sumps is legitimately supported on engineering judgment. As discussed in the preamble to the 1984 proposed rules in 49 FR 23537-23539, the control efficiency of source enclosure is theoretically 100 percent. However, eventual deterioration of the gasket seal (of the cover) may result in occasional leaks, even with proper operation and maintenance. Because mass emissions from these leaks cannot reasonably be measured, EPA conservatively judged the control to obtain a 98-percent emission reduction. The 98-percent efficiency for the light-oil sump is consistent with the 98-percent efficiency assigned to gas-blanketing systems.

The semiannual monitoring provisions do not constitute the control itself. Rather, semiannual monitoring of the light-oil sump cover and gas-blanketed sources is required to ensure proper operation and maintenance (O&M) of the sealed enclosures, i.e., to locate and repair any leaks that may have developed in the control system. Thus, the commenter's recommendation is to allow any alternative control technique provided it uses the same O&M procedures. However, the equivalency of an alternative control to the standard must be based on the emission reduction achieved by the control itself. Then, the provisions necessary for ensuring proper O&M would have to be determined specifically for the alternative control system. Without further information, EPA believes that the 98-percent value is the best estimate available for comparing the efficiency of an alternative control system.

Appendix A

Environmental Impact Analysis

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TABLE A-1. FURNACE COKE BY-PRODUCT RECOVERY PLANTS: COKE-OVEN AND PLANT CAPACITY STATUS (1,000 Mg/yr)

No.	Plant	Battery no.	Battery capacity	Status[a]	No. of ovens	Online	Hot idle	Cold idle	Under construction	Existing plant total
1[b]	LTV Steel, Thomas, AL	1	315	2	65	0	0	315	0	315
2	New Boston, Portsmouth, OH	1	364	0	70	364	0	0	0	364
3	Wheeling-Pitt, Monessen, PA	1A	195	2	37	295	0	195	0	490
		1B	195	0	37					
		2	100	0	19					
4	Lone Star Steel, Lone Star, TX	C	507	0	70	507	0	0	0	507
5	LTV Steel, So. Chicago, IL	2	563	0	60	563	0	0	0	563
6	National Steel, Granite City, IL	A	285	0	45	570	0	0	298	570
		B	285	0	45					
		C	298	3	47					
7	Interlake, Chicago, IL	1	291	0	50	582	0	0	0	582
		2	291	0	50					
8	LTV Steel, Gadsden, AL	2	379	0	65	758	0	0	0	758
		3	379	0	65					
9	Rouge Steel, Dearborn, MI	A	256	0	45	778	0	0	0	778
		Ax	57	0	10					
		B	312	0	55					
		Dx	153	0	27					
10[b]	U.S. Steel, Fairless Hills, PA	1	458	2	82	0	0	916	0	916
		2	458	2	82					
11	LTV Steel, Warren, OH	4	945	0	85	945	0	0	0	945
12[b]	LTV Steel, E. Chicago, IN	4	432	2	75	0	0	948	0	948
		9	516	2	87					
13	Armco Inc., Ashland, KY	3	349	0	76	963	0	0	0	963
		4	614	0	70					
14[b]	Weirton Steel, Brown's Is., WV	1	1,097	2	87	0	0	1,097	0	1,097
15	U.S. Steel, Provo, UT	1	290	0	63	1,160	0	0	0	1,160
		2	290	0	63					
		3	290	0	63					
		4	290	0	63					
16	LTV Steel, Aliquippa, PA	A1	604	0	106	1,218	0	0	0	1,218
		A5	614	0	56					
17	Bethlehem Steel, Lackawanna, NY	7	382	0	76	1,292	0	0	0	1,292
		8	382	0	76					
		9	528	0	73					
18	National Steel, Detroit, MI	4	473	0	78	1,397	0	0	0	1,397
		5	924	0	85					
19[b]	U.S. Steel, Lorain, OH	D	218	2	59	0	0	1,496	0	1,496
		G	218	2	59					
		H	218	2	59					
		I	218	2	59					
		J	208	2	59					
		K	208	2	59					
		L	208	2	59					

(continued)

Footnotes at end of table.

TABLE A-1. (continued)

No.	Plant	Battery no.	Battery capacity	Status[a]	No. of ovens	Online	Hot idle	Cold idle	Under construction	Existing plant total
20	Wheeling-Pitt, E. Steubenville, WV	1	199	0	47	1,509	0	0	0	1,509
		2	199	0	47					
		3	215	0	51					
		8	896	0	79					
21	LTV Steel, Cleveland, OH	1	274	0	51	1,486	0	274	0	1,760
		2	274	0	51					
		3	274	0	51					
		4	274	2	51					
		6	332	0	63					
		7	332	0	63					
22	Armco Inc., Middletown, OH	1	664	0	57	1,776	0	0	0	1,776
		2	664	0	57					
		4	448	0	76					
23	Bethlehem Steel, Burns Harbor, IN	1	895	0	82	1,790	0	0	0	1,790
		2	895	0	82					
24	LTV Steel, Pittsburgh, PA	P1	340	0	59	1,792	0	0	0	1,792
		P2	340	0	59					
		P3N	340	0	59					
		P3S	340	0	59					
		P4	432	0	59					
25[b]	U.S. Steel, Fairfield, AL	2	818	2	57	0	0	1,822	0	1,822
		5	320	2	77					
		6	320	2	77					
		9	364	2	63					
26	Bethlehem Steel, Bethlehem, PA	A	809	0	80	2,253	0	0	0	2,253
		2	522	0	102					
		3	522	0	102					
		5	400	0	80					
27	Bethlehem Steel, Sparrows Pt., MD	1	273	1	63	1,878	536	1,092	0	3,506
		2	263	1	60					
		3	273	2	63					
		4	273	2	63					
		5	273	2	63					
		6	273	2	63					
		11	365	0	65					
		12	365	0	65					
		A	1,148	0	80					
28	Inland Steel, E. Chicago, IN	6	278	0	65	2,885	0	830	0	3,715
		7	372	0	87					
		8	395	0	87					
		9	395	0	87					
		10	450	0	51					
		11	995	0	69					
		C	830	2	56					

Footnotes at end of table. (continued)

TABLE A-1. (continued)

No.	Plant	Battery no.	Battery capacity	Status[a]	No. of ovens	Online	Hot idle	Cold idle	Under construction	Existing plant total
29	U.S. Steel, Gary, IN	1	843	2	85	2,269	1,116	843	0	4,228
		2	995	0	57					
		3	995	0	57					
		5	279	1	77					
		7	279	1	77					
		13	279	1	77					
		15	279	0	77					
		16	279	1	77					
30	U.S. Steel, Clairton, PA	1	296	1	64	3,216	2,078	0	0	5,294
		2	296	1	64					
		3	296	1	64					
		7	296	1	64					
		8	296	1	64					
		9	296	1	64					
		15	302	1	61					
		19	535	0	87					
		20	535	0	87					
		21	535	0	86					
		22	535	0	87					
		B	1,076	0	75					
	Total (30 plants)		42,102		7,100	31,646	3,730	9,828	298	45,804
	(24 plants)		39,508		5,935	31,646	3,730	3,234	298	39,210

Note: Data current as of November 1984.

[a] Status: 0 = online; 1 = hot idle; 2 = cold idle; and 3 = under construction.
[b] Denotes cold idle plants.

TABLE A-2. FOUNDRY COKE BY-PRODUCT RECOVERY PLANTS: COKE-OVEN AND PLANT CAPACITY STATUS
(1,000 Mg/yr)

No.	Plant	Battery no.	Battery capacity	Status[a]	No. of ovens	Online	Hot idle	Cold idle	Under construction	Existing plant total
1	Chattanooga Coke, Chattanooga, TN	1	71	0	24	130	0	0	0	130
		2	59	0	20					
2	IN Gas, Terre Haute, IN	1	66	0	30	132	0	0	0	132
		2	66	0	30					
3	Koppers, Toledo, OH	C	157	0	57	157	0	0	0	157
4	Empire Coke, Holt, AL	1	107	0	20	161	0	0	0	161
		2	54	0	40					
5	Koppers, Erie, PA	A	82	0	23	207	0	0	0	207
		B	125	0	35					
6	Tonawanda, Buffalo, NY	1	299	0	60	299	0	0	0	299
7	Carondolet, St. Louis, MO	1	142	0	40	330	0	0	0	330
		2	64	0	18					
		3	124	0	35					
8[b]	AL Byproducts, Keystone, PA	3	201	2	55	0	0	402	0	402
		4	201	2	55					
9	Citizens Gas, Indianapolis, IN	E	93	0	47	477	0	0	0	477
		H	79	0	41					
		I	305	0	72					
10	Jim Walters, Birmingham, AL	3	125	0	30	499	0	0	0	499
		4	125	0	30					
		5	249	0	60					
11	Shenango, Pittsburgh, PA	1	322	0	56	521	0	0	0	521
		4	199	0	35					
12	Koppers, Woodward, AL		149	0	60	563	0	0	0	563
		2A	97	0	38					
		2B	97	0	40					
		4	145	0	58					
		5	75	0	30					
13	AL Byproducts, Tarrant, AL	A	353	0	78	470	113	0	0	583
		5	113	1	25					
		6	117	0	29					
14	Detroit Coke, Detroit, MI	1	617	0	70	617	0	0	0	617
	Total (14 plants)	31	5,078		1,341	4,563	113	402	0	5,078
	Total (13 plants)	29	4,676		1,231	4,563	113	0	0	4,676

Note: Data current as of November 1984.

[a] Status: 0 = online; 1 = hot idle; 2 = cold idle; and 3 = under construction.

[b] Denotes cold idle plants.

TABLE A-3. FURNACE COKE BY-PRODUCT PLANT OPERATING PROCESSES

No.	Plant	Tar decanter	Tar dewatering	Tar storage	Excess-ammonia liquor storage	Flushing-liquor circ. tank	Tar-interc. sump	Light-oil storage	BTX storage	Benzene storage	Naphthalene processing/handling		
											Denver flo. unit	Naphth. melt pit	Naphth. dry tanks
1	LTV Steel, Thomas, AL	1	1	1	1	1	1	1	0	0	1	1	1
2	New Boston, Portsmouth, OH	1	1	1	1	1	1	1	0	0	0	0	0
3	Wheeling-Pitt, Monessen, PA	1	1	1	1	1	1	1	0	0	0	0	0
4	Lone Star Steel, Lone Star, TX	1	1	1	1	1	1	1	1	0	1	1	1
5	LTV Steel, So. Chicago, IL	1	0	1	1	1	1	1	1	1	0	0	0
6	National Steel, Granite City, IL	1	1	1	1	1	1	1	1	0	1	1	1
7	Interlake, Chicago, IL	1	1	1	1	1	1	1	0	0	1	1	1
8	LTV Steel, Gadsden, AL	1	1	1	1	1	1	1	0	0	1	1	1
9	Rouge Steel, Dearborn, MI	1	1	1	1	1	1	1	1	0	1	1	1
10	U.S. Steel, Fairless Hills, PA	1	1	1	1	1	1	1	0	0	1	1	1
11	LTV Steel, Warren, OH	1	1	1	1	1	1	1	0	0	0	0	0
12	LTV Steel, E. Chicago, IL	1	1	1	1	1	1	1	1	0	0	0	0
13	Armco Inc., Ashland, KY	1	1	1	1	1	1	1	0	0	0	0	0
14	Weirton Steel, Browns Island, WV	1	1	1	1	1	1	1	1	0	1	1	1
15	U.S. Steel, Provo, UT	1	1	1	1	1	1	1	0	1	0	0	0
16	LTV Steel, Aliquippa, PA	1	1	1	1	1	1	1	0	0	0	0	0
17	Bethlehem Steel, Lackawanna, NY	1	1	1	1	1	1	1	1	0	1	1	1
18	National Steel, Detroit, MI	1	1	1	1	1	1	1	0	0	1	1	1
19	U.S. Steel, Lorain, OH	1	1	1	1	1	1	1	0	0	1	1	1
20	Wheeling-Pitt, E. Steubenville, WV	1	1	1	1	1	1	1	0	0	0	0	0
21	LTV Steel, Cleveland, OH	1	1	1	1	1	1	1	1	0	0	0	0
22	Armco Inc., Middletown, OH	1	1	1	1	1	1	1	1	0	0	0	0
23	Bethlehem Steel, Burns Harbor, IN	1	1	1	1	1	1	0	0	0	0	0	0
24	LTV Steel, Pittsburgh, PA	1	1	1	1	1	1	1	0	0	1	1	1
25	U.S. Steel, Fairfield, AL	1	1	1	1	1	1	1	0	0	1	1	1
26	Bethlehem Steel, Bethlehem, PA	1	1	1	1	1	1	1	1	0	1	1	1
27	Bethlehem Steel, Sparrows Pt., MD	1	1	1	1	1	1	1	0	1	0	0	0
28	Inland Steel, E. Chicago, IN	1	1	1	1	1	1	1	0	0	0	0	0
29	U.S. Steel, Gary, IN	1	1	1	1	1	1	1	0	0	1	1	1
30	U.S. Steel, Clairton, PA	1	0	1	1	1	1	1	0	1	0	0	0
	Total	30	28	30	30	30	30	29	10	4	15	15	15

(continued)

TABLE A-3. (continued)

No.	Plant	Direct-water final cooler	Tar-bottom final cooler	Wash-oil final cooler	Light-oil sump	Light-oil decanter/ condenser vent	Wash-oil decanter	Wash-oil circ. tank	Equipment leaks
1	LTV Steel, Thomas, AL	1	0	0	1	1	1	1	1
2	New Boston, Portsmouth, OH	0	1	0	1	1	1	1	1
3	Wheeling-Pitt, Monessen, PA	0	1	0	1	1	1	1	1
4	Lone Star Steel, Lone Star, TX	1	0	0	1	1	1	1	1
5	LTV Steel, So. Chicago, IL	0	0	0	1	1	1	1	1
6	National Steel, Granite City, IL	1	0	0	1	1	1	1	1
7	Interlake, Chicago, IL	1	0	0	1	1	1	1	1
8	LTV Steel, Gadsden, AL	1	0	0	1	1	1	1	1
9	Rouge Steel, Dearborn, MI	1	0	0	1	1	1	1	1
10	U.S. Steel, Fairless Hills, PA	1	0	0	1	1	1	1	1
11	LTV Steel, Warren, OH	0	0	1	1	1	1	1	1
12	LTV Steel, E. Chicago, IN	1	0	0	1	1	1	1	1
13	Armco Inc., Ashland, KY	0	0	0	1	1	1	1	1
14	Weirton Steel, Browns Island, WV	0	0	1	1	1	1	1	1
15	U.S. Steel, Provo, UT	0	1	0	1	1	1	1	1
16	LTV Steel, Aliquippa, PA	0	0	0	1	1	1	1	1
17	Bethlehem Steel, Lackawanna, NY	1	0	0	1	1	1	1	1
18	National Steel, Detroit, MI	1	0	0	1	1	1	1	1
19	U.S. Steel, Lorain, OH	1	0	0	1	1	1	1	1
20	Wheeling-Pitt, E. Steubenville, WV	0	0	1	1	1	1	1	1
21	LTV Steel, Cleveland, OH	0	0	1	1	1	1	1	1
22	Armco Inc., Middletown, OH	1	0	0	1	1	1	1	1
23	Bethlehem Steel, Burns Harbor, IN	0	0	0	0	0	0	0	0
24	LTV Steel, Pittsburgh, PA	1	0	0	1	1	1	1	1
25	U.S. Steel, Fairfield, AL	1	0	0	1	1	1	1	1
26	Bethlehem Steel, Bethlehem, PA	1	0	0	1	1	1	1	1
27	Bethlehem Steel, Sparrows Pt., MD	0	0	1	1	1	1	1	1
28	Inland Steel, E. Chicago, IN	0	1	0	1	1	1	1	1
29	U.S. Steel, Gary, IN	1	0	0	1	1	1	1	1
30	U.S. Steel, Clairton, PA	0	0	0	1	1	1	1	1
	Total	16	4	5	29	29	29	29	29

Note: Data current as of November 1984.

TABLE A-4. FOUNDRY COKE BY-PRODUCT PLANT OPERATING PROCESSES

No.	Plant	Tar decanter	Tar dewatering	Tar storage	Excess-ammonia liquor storage	Flushing-liquor circ. tank	Tar-interc. sump	Light-oil storage	BTX storage	Benzene storage	Naphthalene processing/handling		
											Denver flo. unit	Naphth. melt pit	Naphth. dry tanks
1	Chattanooga Coke, Chattanooga, TN	1	1	1	1	1	1	1	0	0	1	1	1
2	IN Gas, Terre Haute, IN	1	1	1	1	1	1	1	0	0	1	1	1
3	Koppers, Toledo, OH	1	1	1	1	1	1	0	0	0	0	0	0
4	Empire Coke, Holt, AL	1	0	1	1	1	1	1	0	0	1	1	1
5	Koppers, Erie, PA	1	1	1	1	1	1	0	0	0	0	0	0
6	Tonawanda, Buffalo, NY	1	1	1	1	1	1	1	0	0	0	0	0
7	Carondolet, St. Louis, MO	1	1	1	1	1	1	0	0	0	0	0	0
8	AL Byproducts, Keystone, PA	1	1	1	1	1	1	1	1	1	1	1	1
9	Citizens Gas, Indianapolis, IN	1	1	1	1	1	1	0	0	0	1	1	1
10	Jim Walters, Birmingham, AL	1	1	1	1	1	1	1	0	0	1	1	1
11	Shenango, Pittsburgh, PA	1	1	1	1	1	1	1	0	0	0	0	0
12	Koppers, Woodward, AL	1	1	1	1	1	1	1	0	0	0	0	0
13	AL Byproducts, Tarrant, AL	1	1	1	1	1	1	1	0	0	1	1	1
14	Detroit Coke, Detroit, MI	1	1	1	1	1	1	0	0	0	0	0	0
	Total	14	13	14	14	14	14	9	1	1	7	7	7

(continued)

TABLE A-4. (continued)

No.	Plant	Wash-oil final cooler	Direct-water final cooler	Tar-bottom final cooler	Light-oil sump	Light-oil decanter/ condenser vent	Wash-oil decanter	Wash-oil circ. tank	Equipment leaks
1	Chattanooga Coke, Chattanooga, TN	0	1	0	1	1	1	1	1
2	IN Gas, Terre Haute, IN	0	1	0	1	1	1	1	1
3	Koppers, Toledo, OH	0	0	1	0	0	0	0	0
4	Empire Coke, Holt, AL	0	1	0	1	1	1	1	1
5	Koppers, Erie, PA	0	0	0	0	0	0	0	0
6	Tonawanda, Buffalo, NY	0	0	0	0	0	0	0	0
7	Carondolet, St. Louis, MO	0	0	0	0	0	0	0	0
8	AL Byproducts, Keystone, PA	0	1	0	1	1	1	1	1
9	Citizens Gas, Indianapolis, IN	0	1	0	0	0	0	0	0
10	Jim Walters, Birmingham, AL	0	1	0	1	1	1	1	1
11	Shenango, Pittsburgh, PA	0	0	0	1	1	1	1	1
12	Koppers, Woodward, AL	0	0	1	1	1	1	1	1
13	AL Byproducts, Tarrant, AL	0	1	0	1	1	1	1	1
14	Detroit Coke, Detroit, MI	0	0	0	0	0	0	0	0
	Total	0	7	2	8	8	8	8	8

Note: Data current as of November 1984.

TABLE A-5. ESTIMATED NATIONWIDE BASELINE BENZENE EMISSIONS FROM FURNACE AND FOUNDRY COKE BY-PRODUCT RECOVERY PLANTS

Source	Furnace plants			Foundry plants			Furnace and foundry plants		
	No. of affected plants[a]	Capacity,[b] 1,000 Mg/yr	Nationwide emissions, Mg/yr	No. of affected plants[a]	Capacity,[b] 1,000 Mg/yr	Nationwide emissions, Mg/yr	No. of affected plants[a]	Capacity,[b] 1,000 Mg/yr	Nationwide emissions, Mg/yr
1. Direct-water final-cooler cooling tower	16	21,430	5,786	7	2,384	470	23	23,814	6,256
2. Tar-bottom final-cooler cooling tower	4	5,729	401	2	720	37	6	6,449	438
3. Naphthalene processing/ handling	15	19,654	2,103	7	2,384	186	22	22,038	2,289
4. Light-oil decanter/ condenser vent	29	44,014	3,456	9	3,290	158	38	47,304	3,614
5. Tar-intercepting sump	30	45,804	4,351	14	5,078	227	44	50,882	4,578
6. Tar decanter	30	45,804	3,527	14	5,078	184	44	50,882	3,711
7. Tar dewatering	28	39,947	839	13	4,917	49	41	44,864	887
8. Tar storage	30	45,804	550	14	5,078	29	44	50,882	578
9. Light-oil sump	29	44,014	660	9	3,290	27	38	47,304	687
10. Light-oil storage	29	44,014	242	9	3,290	10	38	47,304	253
11. BTX storage	10	11,544	54	2	901	3	12	12,445	57
12. Benzene storage	4	10,523	61	1	402	1	5	10,925	62
13. Flushing liquor circulation tank	30	45,804	412	14	5,078	33	44	50,882	446
14. Excess-ammonia liquor storage tank	30	45,804	412	14	5,078	33	44	50,882	446
15. Wash-oil decanter	29	44,014	154	9	3,290	7	38	47,304	161
16. Wash-oil circulation tank	29	44,014	154	9	3,290	7	38	47,304	161

(continued)

Footnotes at end of tables.

TABLE A-5. (continued)

Source	Furnace plants			Foundry plants			Furnace and foundry plants		
	No. of affected plants[a]	Capacity,[b] 1,000 Mg/yr	Nationwide emissions, Mg/yr	No. of affected plants[a]	Capacity,[b] 1,000 Mg/yr	Nationwide emissions, Mg/yr	No. of affected plants[a]	Capacity,[b] 1,000 Mg/yr	Nationwide emissions, Mg/yr
17. Pump seals	29	44,014	370	9	3,290	101	38	47,304	471
18. Valves	29	44,014	249	9	3,290	68	38	47,304	317
19. Pressure-relief devices	29	44,014	168	9	3,290	46	38	47,304	214
20. Exhausters	29	44,014	17	9	3,290	5	38	47,304	22
21. Sampling connection systems	29	44,014	33	9	3,290	9	38	47,304	42
22. Open-ended lines	29	44,014	11	9	3,290	3	38	47,304	14
Total (rounded)			24,000			1,700			25,700

Note: Data current as of November 1984.

[a] Number of plants having this source (out of a total of 30 furnace plants, 14 foundry plants, or 44 furnace and foundry plants combined; includes plants currently on cold idle.

[b] Capacity of plants with this source.

TABLE A-6. ESTIMATED NATIONWIDE BASELINE VOC^a EMISSIONS FROM FURNACE AND FOUNDRY COKE BY-PRODUCT RECOVERY PLANTS

Source	Furnace plants			Foundry plants			Furnace and foundry plants		
	No. of affected plants^b	Capacity,^{c} 1,000 Mg/yr	Nationwide emissions, Mg/yr	No. of affected plants^b	Capacity,^{c} 1,000 Mg/yr	Nationwide emissions, Mg/yr	No. of affected plants^b	Capacity,^{c} 1,000 Mg/yr	Nationwide emissions, Mg/yr
1. Direct-water final-cooler cooling tower	16	21,430	90,842	7	2,384	7,377	23	23,814	98,219
2. Tar-bottom final-cooler cooling tower	4	5,729	6,302	2	720	578	6	6,449	6,880
3. Naphthalene processing/ handling	15	19,654	3,302	7	2,384	292	22	22,038	3,594
4. Light-oil decanter/ condenser vent	29	44,014	4,931	9	3,290	226	38	47,304	5,157
5. Tar intercepting sump	30	45,804	9,252	14	5,078	482	44	50,882	9,735
6. Tar decanter	30	45,804	7,512	14	5,078	391	44	50,882	7,903
7. Tar dewatering	28	39,947	19,654	13	4,917	1,137	41	44,864	20,791
8. Tar storage	30	45,804	12,871	14	5,078	671	44	50,882	13,542
9. Light-oil sump	29	44,014	942	9	3,290	38	38	47,304	980
10. Light-oil storage	29	44,014	347	9	3,290	15	38	47,304	362
11. BTX storage	10	11,544	77	2	901	4	12	12,445	82
12. Benzene storage	4	10,523	61	1	402	1	5	10,925	62
13. Flushing-liquor circulation tank	30	45,804	591	14	5,078	48	44	50,882	639
14. Excess-ammonia liquor storage tank	30	45,804	591	14	5,078	48	44	50,882	639
15. Wash-oil decanter	29	44,014	219	9	3,290	10	38	47,304	229
16. Wash oil circulation tank	29	44,014	219	9	3,290	10	38	47,304	229

Footnotes at end of tables.

(continued)

TABLE A-6. (continued)

Source	Furnace plants			Foundry plants			Furnace and foundry plants		
	No. of affected plants[b]	Capacity,[c] 1,000 Mg/yr	Nationwide emissions, Mg/yr	No. of affected plants[b]	Capacity,[c] 1,000 Mg/yr	Nationwide emissions, Mg/yr	No. of affected plants[b]	Capacity,[c] 1,000 Mg/yr	Nationwide emissions, Mg/yr
17. Pump seals	29	44,014	528	9	3,290	159	38	47,304	687
18. Valves	29	44,014	355	9	3,290	107	38	47,304	463
19. Pressure-relief devices	29	44,014	240	9	3,290	73	38	47,304	312
20. Exhausters	29	44,014	25	9	3,290	8	38	47,304	33
21. Sampling connection systems	29	44,014	47	9	3,290	14	38	47,304	61
22. Open-ended lines	29	44,014	16	9	3,290	5	38	47,304	21
Total (rounded)			59,200			11,700			170,900

Note: Data current as of November 1984.

[a] Benzene and other VOC.

[b] Number of plants having this source out of a total of 30 furnace plants, 14 foundry plants, or 44 furnace and foundry plants combined; includes plants currently on cold idle.

[c] Capacity of plants with this source.

TABLE A-7. CONTROL OPTION IMPACTS FOR FURNACE PLANTS

Emission source	Control option/ efficiency, %		Controlled emissions, Mg/yr, Benzene/VOC^{a}		Controlled incidence, lives/yr	Annual costs,^{b} 1984 $/yr	Benzene cost effectiveness,^{b,f} 1984 $/Mg aver./incre.		VOC^{a} cost effectiveness,^{b,f} 1984 $/Mg aver./incre.	
Final cooler cooling tower and naphthalene processing/ handling	Baseline^{c}:		8,290	100,000	0.78					
	Tar-bottom final cooler	81	1,900	29,400	0.16	152,600	20	20	2	2
	Wash-oil final cooler	100	0	0	0.00	12,871,380	1,550	6,690	130	430
Tar decanter, tar-intercepting sump, and flushing-liquor circulation tank^{e}	Baseline^{c}:		8,290	17,400	0.99					
	Gas blanketing	98^{d}	270	600	0.02	(1,062,260)	(130)	(130)	(60)	(60)
Tar storage tanks and tar-dewatering tanks^{e}	Baseline^{c}:		1,390	32,500	0.16					
	Gas blanketing	98	30	600	0.003	1,735,070	1,280	1,280	50	50
Light-oil condenser, light-oil decanter, wash-oil decanter and wash-oil circulation tanks	Baseline^{c}:		3,760	5,370	0.39					
	Wash-oil scrubber	90	380	550	0.040	348,320	100	100	70	70
	Gas blanketing	98	80	120	0.009	504,530	140	520	100	360
Excess-ammonia liquor storage tank^{e}	Baseline^{c}:		410	590	0.047					
	Gas blanketing	98	8	11	0.001	849,370	2,100	2,100	1,470	1,470
Light-oil storage tanks and BTX storage tanks^{e}	Baseline^{c}:		300	420	0.039					
	Gas blanketing	98	6	9	0.001	1,119,040	3,860	3,860	2,700	2,700
Benzene storage tanks	Baseline^{c}:		60	60	0.0063					
	Wash-oil scrubber	90	6	6	0.0006	120,570	2,200	2,200	2,200	2,200
	N_2 gas blanketing	98	1	1	0.0001	134,040	2,240	2,760	2,240	2,760
Light-oil sump	Baseline^{c}:		660	940	0.079					
	Cover	98	10	20	0.001	468,470	720	720	500	500
Pumps	Baseline^{c}:		370	530	0.044					
	Quarterly inspections	71	110	150	0.013	29,800	110	110	80	80
	Monthly inspections	83	60	90	0.008	35,780	120	130	81	90
	Dual mechanical seals	100	0	0	0.000	1,067,250	2,890	16,690	2,020	11,780

Footnotes at end of table.

(continued)

TABLE A-7. (continued)

Emission source	Control option/ efficiency, %		Controlled emissions, Mg/yr		Controlled incidence, lives/yr	Annual costs,^{b} 1984 $/yr	Benzene cost effectiveness,^{b,f} 1984 $/Mg		VOC^a cost effectiveness,^{b,f} 1984 $/Mg	
			Benzene	VOC^a			aver.	incre.	aver.	incre.
Valves	Baseline^c:		250	350	0.030					
	Quarterly inspections	63	90	130	0.011	(36,760)	(240)	(240)	(160)	(160)
	Monthly inspections	73	70	100	0.009	(19,760)	(110)	720	(80)	500
	Sealed-bellows valves	100	0	0	0.000	4,324,320	17,380	62,780	12,170	43,950
Exhausters	Baseline^c:		20	30	0.0021					
	Quarterly inspections	55	8	10	0.0011	13,870	1,450	1,450	1,020	1,020
	Monthly inspections	64	6	9	0.0008	30,160	2,740	11,230	1,920	7,870
	Degassing reservoir vents	100	0	0	0.0000	437,320	25,130	68,820	17,590	44,640
Pressure-relief devices	Baseline^c:		170	240	0.020					
	Quarterly inspections	44	90	130	0.011	(30,940)	(410)	(410)	(290)	(290)
	Monthly inspections	52	80	110	0.009	(26,990)	(310)	290	(210)	200
	Rupture disc system	100	0	0	0.000	153,820	920	2,270	640	1,590
Sampling connection systems	Baseline^c:		30	50	0.0039					
	Closed-purge sampling	100	0	0	0.0000	40,770	1,250	1,250	870	870
Open-ended lines	Baseline^c:		10	20	0.0013					
	Cap or plug	100	0	0	0.0000	7,110	640	640	450	450
Naphthalene processing/ handling^g	Baseline^c:		2,100	3,300	0.29					
	Mixer-settler	100	0	0	0.00	1,603,960	760	760	490	490

Note: Data current as of November 1984.

[a] VOC estimates include benzene.

[b] Parentheses denote cost savings.

[c] Baseline numbers represent relatively uncontrolled levels.

[d] 95 % efficiency for tar decanter.

[e] Wash-oil scrubbers are more costly and less effective than gas blanketing for these sources.

[f] "Average" means compared to baseline; "incremental" means compared to the next less stringent control option.

[g] The mixer-settler control option for naphthalene processing and handling is shown separately to address a comment on new indirect cooling technology that would not necessarily control naphthalene processing emissions.

TABLE A-8. CONTROL OPTION IMPACTS FOR FOUNDRY PLANTS

Emission source	Control option/ efficiency, %		Controlled emissions, Mg/yr		Controlled incidence, lives/yr	Annual costs,[b] 1984 $/yr	Benzene cost effectiveness,[b,f] 1984 $/Mg		VOC[a] cost effectiveness,[b,f] 1984 $/Mg	
			Benzene	VOC[a]			Aver.	Incre.	Aver.	Incre.
Final cooler cooling tower and naphthalene processing/ handling	Baseline[c]:		690	8,250	0.077					
	Tar-bottom final cooler	81	160	2,490	0.012	305,550	570	570	50	50
	Wash-oil final cooler	100	0	0	0.000	2,831,680	4,090	15,900	340	1,000
Tar decanter, tar-intercepting sump, and flushing-liquor circulation tank[e]	Baseline[c]:		440	920	0.070					
	Gas blanketing	98[d]	10	30	0.003	410,390	960	960	460	460
Tar storage tanks and tar-dewatering tanks[e]	Baseline[c]:		80	1,810	0.012					
	Gas blanketing	98	2	40	0.001	397,510	5,260	5,260	220	220
Light-oil condenser, light-oil decanter, wash-oil decanter and wash-oil circulation tanks[e]	Baseline[c]:		170	250	0.023					
	Gas blanketing	98	3	5	0.0005	238,200	1,420	1,420	990	990
Excess-ammonia liquor storage tank[e]	Baseline[c]:		30	50	0.0049					
	Gas blanketing	98	0.7	1	0.0001	277,630	8,490	8,490	5,920	5,920
Light-oil storage tanks and BTX storage tanks[e]	Baseline[c]:		10	20	0.0021					
	Gas blanketing	98	0.3	0.4	0.00004	251,140	19,520	19,500	13,640	13,640
Benzene storage tanks[e]	Baseline[c]:		1.0	1.0	0.00041					
	N_2 gas blanketing	98	0.1	0.1	0.00001	14,360	11,640	11,640	11,640	11,640
Light-oil sump	Baseline[c]:		30	40	0.004					
	Cover[g]	98	0.5	0.8	0.000	44,290	1,700	1,700	1,190	1,190
Pumps	Baseline[c]:		100	160	0.019					
	Quarterly inspections	71	30	50	0.006	9,360	130	130	80	80
	Monthly inspections	83	20	30	0.003	11,270	134	150	90	100
	Dual mechanical seals	100	0	0	0.000	323,960	3,200	18,500	2,030	11,730

(continued)

Footnotes at end of table.

TABLE A-8. (continued)

Emission source	Control option/ efficiency, %		Controlled emissions, Mg/yr		Controlled incidence, lives/yr	Annual costs,[b] 1984 $/yr	Benzene cost effectiveness,[b,f] 1984 $/Mg		VOC[a] cost effectiveness,[b,f] 1984 $/Mg	
			Benzene	VOC[a]			Aver.	Incre.	Aver.	Incre.
Valves	Baseline[c]:		70	110	0.013					
	Quarterly inspections	63	30	40	0.005	(10,920)	(260)	(260)	(160)	(160)
	Monthly inspections	73	20	30	0.004	(5,740)	(120)	800	(70)	510
	Sealed-bellows valves	100	0	0	0.000	1,310,400	19,250	69,530	12,220	44,170
Exhausters	Baseline[c]:		4.9	7.7	0.00091					
	Quarterly inspections	55	2.2	3.4	0.00040	4,310	1,590	1,590	1,010	1,010
	Monthly inspections	64	1.8	2.8	0.00030	9,360	3,010	12,330	1,910	7,900
	Degassing reservoir vents	100	0.0	0.0	0.00000	135,720	27,640	70,200	17,540	44,490
Pressure-relief devices	Baseline[c]:		50	70	0.0085					
	Quarterly inspections	44	30	40	0.0047	(9,320)	(450)	(450)	(290)	(290)
	Monthly inspections	52	20	30	0.0040	(8,110)	(330)	320	(210)	200
	Rupture disc system	100	0	0	0.0000	47,010	1,020	2,520	650	1,600
Sampling connection systems	Baseline[c]:		9	14	0.0017					
	Closed-purge sampling	100	0	0	0.0000	12,380	1,390	1,390	880	880
Open-ended lines	Baseline[c]:		3	5	0.00056					
	Cap or plug	100	0	0	0.00000	2,220	730	730	460	460
Naphthalene processing/ handling[g]	Baseline[c]:		190	290	0.034					
	Mixer-settler	100	0	0	0.000	453,080	2,430	2,430	1,550	1,550

Note: Data current as of November 1984.

[a] VOC estimates include benzene.

[b] Parentheses denote cost savings.

[c] Baseline numbers represent relatively uncontrolled levels.

[d] 95% efficiency for tar decanter.

[e] Wash-oil scrubbers are more costly and less effective than gas blanketing for these sources.

[f] "Average" means compared to baseline; "incremental" means compared to the next less stringent control option.

[g] The mixer-settler control option for naphthalene processing and handling is shown separately to address a comment on new indirect cooling technology that would not necessarily control naphthalene processing emissions.

TABLE A-9. EFFECT OF CONTROL OPTIONS ON REDUCING BENZENE EMISSIONS AT FURNACE AND FOUNDRY COKE BY-PRODUCT RECOVERY PLANTS

		Furnace Plants			Foundry Plants			Furnace and Foundry Plants		
Source	Control option	No. of affected plants[a]	National benzene emissions, Mg/yr	Controlled benzene emissions, Mg/yr	No. of affected plants[a]	National benzene emissions, Mg/yr	Controlled benzene emissions, Mg/yr	No. of affected plants[a]	National benzene emissions, Mg/yr	Controlled benzene emissions, Mg/yr
1. All sources	No national emission standard	30	24,000	24,000	14	1,690	1,690	44	25,900	25,900
2. Final-cooler cooling tower	1. Tar-bottom final cooler	16	8,290	1,901	7	693	159	23	8,983	2,060
	2. Wash-oil final cooler	20	8,290	0	9	693	0	29	8,983	0
3. Light-oil decanter/ condenser vent	1. Wash-oil scrubber	29	3,456	356	9	158	16	38	3,614	372
	2. Coke-oven gas blanketing	29	3,456	78	9	158	3	38	3,614	82
4. Tar-intercepting sump	Coke-oven gas blanketing	30	4,351	87	14	227	5	44	4,578	92
5. Tar decanter	Coke-oven gas blanketing	30	3,527	176	14	184	9	44	3,711	186
6. Tar dewatering	1. Wash-oil scrubber	28	839	84	13	49	5	41	887	89
	2. Coke-oven gas blanketing	28	839	17	13	49	1	41	887	18
7. Tar storage	1. Wash-oil scrubber	30	550	55	14	29	3	44	578	58
	2. Coke-oven gas blanketing	30	550	11	14	29	0.6	44	578	12
8. Light-oil sump	Sealed cover	29	660	13	9	27	0.5	38	687	14
9. Light-oil storage	1. Wash-oil scrubber	29	242	24	9	10	1	38	253	26
	2. Coke-oven gas blanketing	29	242	5	9	10	0.2	38	253	5
10. BTX storage	1. Wash-oil scrubber	10	54	7	2	3	0.3	12	57	7
	2. Coke-oven gas blanketing	10	54	1	2	3	0.1	12	57	1
11. Benzene storage	1. Wash-oil scrubber	4	61	6	1	1	0.1	5	62	6
	2. Gas blanketing	4	61	1	1	1	0.03	5	62	1
12. Flushing-liquor circulation tank	Coke-oven gas blanketing	30	412	8	14	33	0.7	44	446	9
13. Excess-ammonia-liquor storage	Coke-oven gas blanketing	30	412	8	14	33	0.7	44	446	9
14. Wash-oil decanter	1. Wash-oil scrubber	29	154	15	9	7	6.1	38	161	21
	2. Coke-oven gas blanketing	29	154	3	9	7	0.1	38	161	3
15. Wash-oil circulation tank	1. Wash-oil scrubber	29	154	15	9	7	6.1	38	161	21
	2. Coke-oven gas blanketing	29	154	3	9	7	0.1	38	161	3

Footnote at end of table.

(continued)

TABLE A-9. (continued)

Source	Control option	Furnace Plants			Foundry Plants			Furnace and Foundry Plants		
		No. of affected plants[a]	National benzene emissions, Mg/yr	Controlled benzene emissions, Mg/yr	No. of affected plants[a]	National benzene emissions, Mg/yr	Controlled benzene emissions, Mg/yr	No. of affected plants[a]	National benzene emissions, Mg/yr	Controlled benzene emissions, Mg/yr
16. Pump seals	1. Quarterly inspection	29	370	108	9	101	29	38	471	137
	2. Monthly inspection	29	370	62	9	101	17	38	471	79
	3. Dual mechanical seals	29	370	0	9	101	0	38	471	0
17. Valves	1. Quarterly inspection	29	249	93	9	68	25	38	317	118
	2. Monthly inspection	29	249	69	9	68	19	38	317	88
	3. Sealed-bellows valves	29	249	0	9	68	0	38	317	0
18. Pressure-relief devices	1. Quarterly inspection	29	168	93	9	46	26	38	214	119
	2. Monthly inspection	29	168	80	9	46	22	38	214	101
	3. Rupture disc	29	168	0	9	46	0	38	214	0
19. Exhausters	1. Quarterly inspection	29	17	8	9	5	2	38	22	10
	2. Monthly inspection	29	17	6	9	5	2	38	22	8
	3. Rupture disc	29	17	0	9	5	0	38	22	0
20. Sampling connection systems	Closed purge sampling	29	33	0	9	9	0	38	42	0
21. Open-ended lines	Cap or plug	29	11	0	9	3	0	38	14	0
	Total (rounded)		24,000			1,700			25,700	

Note: Data current as of November 1984.

[a] Number of plants having this source out of a total of 30 furnace plants, 14 foundry plants, or 44 furnace and foundry plants combined; includes plants currently on cold idle.

TABLE A-10. EFFECT OF BENZENE CONTROL OPTIONS ON REDUCING VO[a] EMISSIONS AT FURNACE AND FOUNDRY COKE BY-PRODUCT RECOVERY PLANTS

Source	Control option	Furnace plants			Foundry plants			Furnace and foundry plants		
		No. of affected plants	VOC nationwide emissions, Mg/yr	Controlled VOC emissions, Mg/yr	No. of affected plants	VOC nationwide emissions, Mg/yr	Controlled VOC emissions, Mg/yr	No. of affected plants	VOC nationwide emissions, Mg/yr	Controlled VOC emissions, Mg/yr
1. All sources	No national emission standard	30	159,200	159,200	14	11,700	11,700	44	170,900	170,900
2. Final-cooler cooling tower	1. Tar-bottom final cooler	16	100,446	29,400	7	8,248	2,943	23	108,694	32,343
	2. Wash-oil final cooler	20	100,446	0	9	8,248		29	108,694	0
3. Light-oil decanter/ condenser vent	1. Wash-oil scrubber	29	4,931	493	9	226	23	38	5,157	516
	2. Coke-oven gas blanketing	29	4,931	112	9	226	5	38	5,157	116
4. Tar-intercepting sump	Coke-oven gas blanketing	30	9,252	185	14	482	10	44	9,735	195
5. Tar decanter	Coke-oven gas blanketing	30	7,512	376	14	391	20	44	7,903	395
6. Tar dewatering	1. Wash-oil scrubber	28	19,654	1,965	13	1,137	114	41	20,791	2,079
	2. Coke-oven gas blanketing	28	19,654	393	13	1,137	23	41	20,791	416
7. Tar storage	1. Wash-oil scrubber	30	12,871	1,287	14	671	67	44	13,542	1,354
	2. Coke-oven gas blanketing	30	12,871	257	14	671	13.4	44	13,542	271
8. Light-oil sump	Sealed cover	29	942	19	9	38	0.8	38	980	20
9. Light-oil storage	1. Wash-oil scrubber	29	347	35	9	15	1	38	362	36
	2. Coke-oven gas blanketing	29	347	7	9	15	0.3	38	362	7
10. BTX storage	1. Wash-oil scrubber	10	77	10	2	4	0.4	12	82	10
	2. Coke-oven gas blanketing	10	77	2	2	4	0.1	12	82	2
11. Benzene storage	1. Wash-oil scrubber	4	61	6	1	1	0.1	5	62	6
	2. Gas blanketing	4	61	1	1	1	0.03	5	62	1
12. Flushing-liquor circulation tank	Coke-oven gas blanketing	30	591	12	14	48	1	44	639	13
13. Excess-ammonia liquor storage tank	1. Wash-oil scrubber	30	591	59	14	48	5	44	639	64
	2. Coke-oven gas blanketing	30	591	12	14	48	1	44	639	13
14. Wash-oil decanter	1. Wash-oil scrubber	29	219	22	9	10	1	38	229	23
	2. Coke-oven gas blanketing	29	219	5	9	10	0.2	38	229	5
15. Wash-oil circulation tank	1. Wash-oil scrubber	29	219	22	9	10	1	38	229	23
	2. Coke-oven gas blanketing	29	219	5	9	10	0.2	38	229	5

Footnotes at end of table.

(continued)

TABLE A-10. (continued)

Source	Control option	Furnace plants			Foundry plants			Furnace and foundry plants		
		No. of affected plants	VOC nationwide emissions, Mg/yr	Controlled VOC emissions, Mg/yr	No. of affected plants	VOC nationwide emissions, Mg/yr	Controlled VOC emissions, Mg/yr	No. of affected plants	VOC nationwide emissions, Mg/yr	Controlled VOC emissions, Mg/yr
16. Pump seals	1. Quarterly inspection	29	528	154	9	159	46	38	687	200
	2. Monthly inspection	29	528	88	9	159	27	38	687	115
	3. Dual mechanical seals	29	528	0	9	159	0	38	687	0
17. Valves	1. Quarterly inspection	29	355	132	9	107	40	38	463	172
	2. Monthly inspection	29	355	99	9	107	30	38	463	129
	3. Sealed-bellows valves	29	355	0	9	107	0	38	463	0
18. Pressure relief devices	1. Quarterly inspection	29	240	133	9	73	40	38	312	173
	2. Monthly inspection	29	240	114	9	73	34	38	312	148
	3. Rupture disc	29	240	0	9	73	0	38	312	0
19. Exhausters	1. Quarterly inspection	29	25	11	9	8	3	38	33	15
	2. Monthly inspection	29	25	9	9	8	3	38	33	12
	3. Rupture disc	29	25	0	9	8	0	38	33	0
20. Sampling connection systems	Closed purge sampling	29	47	0	9	14	0	38	61	0
21. Open-ended lines	Cap or plug	29	16	0	9	5	0	38	21	0

Note: Data current as of November 1984.

[a] Benzene and other VOC.

[b] Number of plants having this source out of a total of 30 furnace plants, 14 foundry plants, or 44 furnace and foundry plants combined; includes plants currently on cold idle.

TABLE A-11. ENERGY USE AT MODEL BY-PRODUCT PLANTS[a]

User	Furnace plants[b]		Foundry Plants[c]	
	Steam, Mg/yr	Electricity, MWh/yr	Steam, Mg/yr	Electricity, MWh/yr
Gas blanketing				
Tar decanter, tar-intercepting sump, and flushing liquor circulation tank	350	--	162	--
Tar dewatering, tar storage	440	--	111	--
Excess ammonia-liquor storage tank	126	--	--	--
Condenser, light-oil decanter, wash-oil decanter, and circulation tank	174	--	116	--
Wash-oil scrubber				
Excess ammonia liquor storage tank	24	0.4		
Benzene storage tank	--	0.9		
Final cooler				
Tar-bottom final cooler	380	98	127	26
Wash-oil final cooler	1,210	1,330	303	333

[a] For information on derivation of estimates, see Docket A-79-16, item IV-B-11.
[b] 4,000 Mg coke/day.
[c] 1,000 Mg coke/day.

TABLE A-12. EMISSIONS OF COKE-OVEN GAS FROM SELECTED FURNACE AND FOUNDRY COKE-OVEN BY-PRODUCT PLANT SOURCES

Source	Furnace plant emissions, ℓ gas/min/Mg coke/day	Foundry plant emissions, ℓ gas/min/Mg coke/day
Tar decanter	10.0	7.5
Light-oil condenser	0.18	0.14
Tar dehydrator	2.9	2.2
Tar storage	2.8	2.1

TABLE A-13. YIELDS--FOUNDRY VS. FURNACE COKE PLANTS

Year	Coal-to-coke ratio		Light oil yield, gal/ton of coal		Tar yield, gal/ton of coal		Gas yield, 1,000 ft^3/ton coal		Light oil/gas conc., gal light oil/1,000 ft^3		Light oil/tar conc., gal/gal	
	Merch.[a]	Furn.	Merch.	Furn.	Merch.	Furn.	Merch.	Furn.	Merch.	Furn.	Merch.	Furn.
1976	1.35	1.46	1.67	2.58	5.26	7.77	9.21	11.02	0.18	0.23	0.32	0.33
1977												
1978	1.31	1.47	1.77	2.9	5.52	7.78	9.23	11.2	0.19	0.26	0.32	0.37
1979	1.34	1.47	1.82	2.51	5.94	7.86	9.03	11.04	0.2	0.23	0.31	0.32
1980	1.34	1.46	1.82	2.67	5.97	8.27	8.94	11.14	0.2	0.24	0.3	0.32
1981												
1982	1.32	1.47										
1983	1.29	1.46				8.08		10.37				
Average ratios-- merch./furn.	1.325	1.465	1.77	2.665 .664	5.6725	7.952 .713	9.1025	10.954 .831	0.1925	0.24 0.802	0.3125	0.335 0.933

[a] Merchant coke plants are assumed to be the same as foundry coke plants.

TABLE A-14. CORRECTION FACTOR COMPUTATION FOR FOUNDRY COKE BY-PRODUCT RECOVERY PLANTS

Source	Concentration adjustment	Volume (throughput) adjustment		Total correction
Light oil plant	Benzene in light oil (63.5/70)=0.907	Light oil yield coke basis x(0.664)(1.325/1.465)	=	0.54
Water contact with coke oven gas	Benzene in light oil Light oil in coke oven gas (0.907x0.802)	x 1	=	0.73
Tar sources	Benzene in light oil Light oil in coke oven gas (0.907x0.802)	Tar yield coke basis x(0.713)(1.325/1.465)	=	0.47
Equip. leaks	Benzene in light oil (0.907)	x 1	=	0.91

TABLE A-15. UNCONTROLLED BENZENE EMISSIONS FACTORS FOR FURNACE AND FOUNDRY COKE BY-PRODUCT PLANTS

Source	Furnace plant emission factors g benzene/Mg coke	Foundry Plant emission factors g benzene/Mg coke
Cooling tower		
Direct-water	270	197
Tar-bottom	70	51
Naphthalene separation and processing	107	79
Light-oil condenser vent	89	48
Tar intercepting sump	90	45
Tar dewatering	21	9.9
Tar decanter	77	36
Tar storage	12	5.6
Light-oil sump	15	8.1
Light-oil storage	5.8	3.1
BTX storage	5.8	3.1
Benzene storage	5.8	3.1
Flushing-liquor circulation tank	9	6.6
Excess-ammonia liquor tank	9	6.6
Wash-oil decanter	3.8	2.1
Wash-oil circulation tank	3.8	2.1
Pump seals	a	a
Valves	a	a
Pressure-relief devices	a	a
Exhausters	a	a
Sample connections	a	a
Open-ended lines	a	a

[a] Emission factors are not related to coke production capacity and are listed in Table A-16.

TABLE A-16. BENZENE EMISSION FACTORS FOR EQUIPMENT LEAKS

	Percent of sources leaking initially	VOC emission factor, kg/source day	Furnace plant Benzene emission factors, kg benzene/source day		Foundry plant benzene emission factors kg benzene/source day	
			Plant A[a]	Plant B[b]	Plant A[a]	Plant B[b]
Valves	11	0.26	0.18	0.22	0.16	0.20
Pumps	24	2.7	1.9	2.3	1.7	2.1
Exhausters	35	1.2	0.28[c]	0.28[c]	0.25	0.25
Pressure relief devices	d	3.9	2.7	3.4	2.5	3.1
Sampling connections	d	0.36	0.25	0.31	0.23	0.28
Open-ended lines	d	0.055	0.038	0.047	0.035	0.043

[a] Plant A recovers light oil. The amount of benzene in the light oil is assumed to be 70 percent at furnace plants and 63.5 percent at foundry plants.

[b] Plant B recovers refined benzene. The amount of benzene averaged over the light oil and refined benzene is assumed to be 86 percent at furnace plants and 78 percent at foundry plants.

[c] 23.5% benzene in nonmethane hydrocarbon.

[d] This type of information would not be appropriate for relief valve overpressure, sampling connections, and open-ended lines.

Appendix B

Cost Impact Analysis

APPENDIX B: COST IMPACT ANALYSIS

B.1 DEVELOPMENT OF REVISED CONTROL COST ESTIMATES

In response to comments received during the public comment period for the proposed coke-oven by-product plant National Emission Standards for Hazardous Air Pollutants (NESHAP), an in-depth review of the benzene control cost estimates was undertaken. The nature of the comments received touched virtually all aspects of the cost-estimating methodology. This report [Appendix B] documents the various elements of the review process, the revisions made to the cost-estimating methodology, and the resulting changes in nationwide cost impacts.

The general theme of the comments received was that control costs for the industry had been underestimated, and therefore the cost and economic impacts were understated. The American Iron and Steel Institute (AISI) supplied cost factors and cost estimates for particular portions of the proposed control systems on the basis of data supplied by member companies. The information supplied ranged from cost factors for individual components of the control systems to a cost estimate for the proposed controls applied to an entire plant. Because the differences between the cost information received and U.S. Environmental Protection Agency (EPA) cost estimates was large in some cases, a complete review was undertaken.

To begin the review, additional information supporting the cost data provided by AISI was requested. At least three member companies had contributed specific cost data. However, this step alone was not expected to provide sufficient explanation for all the differences between EPA and commenters' cost data. Simultaneously, plans were developed to have a firm not previously involved in the cost-estimating efforts prepare a set of unit cost factors for gas-blanketing systems. These new factors then could be compared with those used by EPA and those supplied by the commenters. To have the unit cost factors reflect conditions imposed by a real plant situation, Bethlehem Steel was asked to allow EPA and/or their contractors to visit the Bethlehem, Pennsylvania, plant and use the conditions existing there as the basis for unit costs. A second purpose of the visit to the Bethlehem plant was to generate a cost estimate for applying positive-pressure gas blanketing to all sources covered by the proposed regulation for comparison with the Bethlehem plant cost estimate contained in the AISI comments.

The CRS Sirrine was retained to develop the unit cost factors and overall cost estimate for the specific case of the Bethlehem plant (thus avoiding any potential conflict of interest). The company was selected because its staff has not done much work with steel plants and particularly coke-oven facilities. However, they have considerable experience with petroleum refinery and petrochemical plant engineering and cost estimating (these plants handle similar materials, e.g., oils, tars, explosive mixtures). The EPA, through Research Triangle Institute (RTI), supplied copies of the proposed regulation, the background information document (BID) for the proposed regulation, and estimates of the gaseous emission rates from the various by-product plant sources to CRS Sirrine. Bethlehem Steel provided plant drawings, estimated pumping rates, and processed vessel size information to EPA for CRS Sirrine as requested. Bethlehem Steel also provided information on in-plant restrictions on welding and safety matters.

The direction given to CRS Sirrine was to develop cost estimates for safe positive-pressure gas-blanketing controls applied to the various groups of sources within the Bethlehem plant. In doing this, they were instructed to make use of existing connection points and existing support structures for piping, where possible, and to use pipe routings, tank roofing, and vessel closure methods that would tend to minimize costs. They were also informed of the nature of the compounds in the blanketing gas and the vapor space over the process liquids, as well as the need to avoid condensation and subsequent plugging that might result in the gas-blanketing pipelines.

The plant visit for cost estimation purposes was made on February 19 and 20, 1985. Representatives from RTI, CRS Sirrine, Bethlehem Steel, and United Engineers (the engineering firm supplying the cost estimate contained in AISI's comments) were present at the Bethlehem plant during this effort. The CRS Sirrine developed the required cost estimates and gave the results to EPA and RTI in the form of a report titled Benzene Emissions Control Estimate (Docket Item IV-J-8). The report provided an overall cost estimate for positive-pressure gas-blanketing systems applied to six groups of sources in the plant, as well as light-oil sump covers and roof installation for tar dewatering tanks and an excess ammonia-liquor storage tank. The wide range of pipe sizes, valves, and other piping hardware used in the control systems estimate provided the desired unit cost information.

National Steel, Armco, and Bethlehem Steel (including United Engineers) contributed additional background information in response to EPA's request for more details for the cost comment evaluation. Ultimately, much of the industry-contributed data were used in the development of the revised cost estimates.

B.2 COMPARISON OF UNIT COST FACTORS

One of the major findings from the Bethlehem plant cost study was that, in general, the unit cost factors for piping and piping hardware should be increased. The unit cost factors for piping and piping hardware developed for CRS Sirrine's estimate were higher than those used in the BID for the proposed standards, and they were more in the range of the unit cost factors contained in the comments received. A principal factor contributing to the difference was labor cost for installation of the piping. The revised factors are presented later in this report. They are basically a composite of the Sirrine and industry-supplied data.

The use of the Bethlehem plant for the cost study provided a basis for estimating the costs resulting from roof additions to tanks not currently covered. There was no provision for this cost element in the proposal BID estimates; this cost has been added to the control cost estimates for tar dewatering and excess ammonia-liquor storage tanks. Another result from the Bethlehem cost study was the addition of pipe supports for the minimum gas-blanketing cost cases. The proposal BID estimates included pipe supports only in the maximum cost cases. Pipe support costs also were added to the wash-oil scrubbers based on data provided in industry comments. The operating labor costs for wash-oil scrubbers were increased as a result of the higher hourly labor rates developed during the review. Costs for sealing all process vessels and installing pressure/vacuum relief valves also were added for both gas-blanketing and wash-oil scrubber cases.

A review of the United Engineers' control cost estimates for final-cooler cooling towers (prepared for Bethlehem Steel and submitted in the AISI comments) suggested some appropriate revisions to the EPA cost estimates for those controls. The proposal BID estimate for the tar-bottom mixer-settler included no allowance for piping to and from the new equipment. In some plants this may be a significant cost if the new equipment cannot be located immediately adjacent to the existing final cooler equipment. Piping costs were added for the revised cost estimates. After considering the number of pumps and vessels required in the tar bottom mixer-settler installation, source operating labor also was added to the annualized costs.

The United Engineers' cost estimate for wash-oil final coolers indicated that some use could be made of existing direct-water final-cooler equipment in the conversion to a wash-oil cooler scheme. The capital costs estimated by United Engineers for Bethlehem Steel's Bethlehem plant were significantly lower than the proposal BID cost estimates for a wash-oil final cooler installation. In their comments on the proposed regulation, AISI said one of the member companies had a 1981 budgetary cost estimate for a wash-oil final cooler of $7.4 million (1984 dollars) installed in a 2,500 Mg/day plant, much higher than EPA estimates. The EPA requested further details about this cost estimate. Rather than supplying the requested information, the company supplied newer costs estimates for other types of final coolers. One estimate was for a tar-bottom final cooler, and the other two estimates were for indirect cooling schemes that would achieve final cooler and naphthalene processing emission reductions equivalent to wash-oil final coolers.

One indirect scheme uses warm wash-oil absorption of naphthalene upstream of the final cooler with final cooling provided by direct water contact with gas. However, the direct contact water is cooled indirectly in a heat exchanger thereby avoiding atmospheric emissions from the direct contact water. The capital cost for this system was estimated at \$1.5 million for a 1,600 Mg/day plant.

The other indirect scheme uses a cross-tube cooler to cool the gas. Tar is injected into the gas-side of the cooler to keep condensed naphthalene in solution. The condensed water and tar-containing naphthalene are returned to the collecting main. The cooling fluid is water flowing through tubes of the heat exchanger, never coming into direct contact with the coke oven gas. The capital cost of this system was estimated at \$2.0 million for a 1,600 Mg/day plant.

According to Dravo/Still, an equipment vendor and design firm, the latter indirect cooling scheme is in use at Dofasco in Hamilton, Ontario. Warm wash-oil absorption of naphthalene is in use at Armco's Middletown plant; however, the direct water used to cool the gas at Armco is cooled in an atmospheric cooling tower rather being cooled indirectly.

The cost of the warm wash-oil absorption with indirect cooling of the cooling water is about the same (scaled to equivalent plant size) as the United Engineers' estimate for retrofitting a wash-oil final cooler to the Bethlehem plant. The cost estimate for indirect cooling with the cross-tube cooler and naphthalene absorption by tar is about 25 percent higher (when scaled to equivalent plant size). The United Engineers' estimate was selected as the basis for the revised wash-oil final cooler costs. Dravo/Still indicated the cross-tube cooler is more expensive because reuse of existing equipment is difficult with this final cooler scheme.

One other unit cost related to final coolers was revised. The cost of makeup wash oil for wash-oil final cooler systems was estimated in the proposal BID at \$0.11/kg. This unit cost was increased for the current cost estimates to \$0.34/kg or \$283/m^3 on the basis of information provided by Shenango Inc. The quantity of makeup wash oil required, however, was revised downward by a significant amount from the proposal BID. Comparison of the old makeup wash-oil estimates to potential losses of wash oil indicated that the proposal BID substantially overestimated the required makeup wash oil for final coolers.

B.3 COMPARISON OF WHOLE PLANT ESTIMATE

The changes to the unit cost-estimating factors cited above do not account for all the cost differences between EPA cost estimates and those submitted by AISI for the Bethlehem plant. Study of the Bethlehem plant cost estimates contained in the AISI comments revealed that some of the sources included in their control systems were not required to be controlled by the proposed regulation. This was partially attributable to questions about source definitions in the proposed regulation. As a result, the source definition for excess ammonia-liquor storage tanks has been changed. Elimination of costs for those sources not requiring control reduces the gap between the two estimates.

Assumed pipe sizes for gas-blanketing control systems was another area of difference between the EPA and AISI estimates for the Bethlehem plant. In general, the pipe sizes indicated in the industry cost estimate exceeded the sizes assumed in the EPA design for gas-blanketing control systems. The system design presented by Sirrine in their study of the Bethlehem plant generally used smaller gas blanket pipe diameters than either EPA or industry estimates. Sirrine argued that the small gas flow rates expected to and from the various process vessels only required smaller pipe sizes. According to Sirrine, the more uniform heating achievable by heat tracing the smaller pipe sizes and the higher flow rates that would occur in smaller pipe sizes would reduce the likelihood of condensation and resultant plugging rather than increase it. The EPA ultimately was influenced more by the fact that the proposal BID estimates were based on pipe sizes used in existing gas-blanketing systems. On the whole, the pipe sizes for the revised gas-blanketing cost estimates were neither increased or decreased. This fact explains some of the remaining differences between EPA and industry estimates.

B.4 OTHER COST ELEMENT REVISIONS

Armco and Bethlehem Steel submitted cost estimates for wash-oil scrubbers applied to specific sources in some of their plants. Comparison of their data with the proposal BID data for wash-oil scrubbers suggested a more appropriate way to estimate costs for scrubber applications. The proposal BID estimates used scrubber shell area as the basis for scrubber capital cost, with shell area estimated roughly from the expected gas flows to be treated. The industry cost estimates appeared to be directly proportional to the number of sources to be treated rather than the size of the sources. For the majority of emissions sources for which wash-oil scrubbers were costed, the gas flow rate is intermittent. The highest flow would tend to occur during pumping into the tank, when flow rate would be controlled by the pumping rate. Pump capacity is not expected to vary in direct proportion to tank size, but rather over a narrower range, because a particular pump capacity could handle a range of tank capacities by varying pumping size. For these reasons, we agree that the number of sources is a more appropriate basis for the estimate. The wash-oil scrubber unit costs were revised. The result of this change is that the costs for wash-oil scrubbers applied to medium and large plants have increased compared to the estimates at proposal.

Plan drawings of by-product plant facilities submitted in support of the AISI comments suggested another revision to the cost estimates. The drawings indicated that the number of light-oil, benzene-toluene-xylene (BTX), and benzene storage tanks for plants of specific size were generally higher than was assumed in the model plants used to develop the proposal BID cost-estimating equations. The number of these tanks in the model facilities was, therefore, increased. This revision when combined with the one described above has increased the costs estimates for all plants recovering light oil. Table B-1 lists the revised cost factors used in developing the revised capital and operating cost estimates.

B.5 EXTENSION OF UNIT COST FACTORS TO PLANT COST ESTIMATES

The unit cost factors provided in Tables B-1 and B-2 were extended into full plant cost estimates in the same manner as presented in Chapter 8 of the proposal BID. Piping distances and numbers of process equipment were specified for each model plant size and each group of emitting sources. To reflect the variation that is typical from plant to plant, minimum and maximum values were specified for piping distances and other control equipment elements. Minimum and maximum values also were specified for certain of the unit cost factors such as pipe supports and wash oil scrubbers . For each model plant, minimum and maximum capital costs were estimated by multiplying the equipment element numbers by the

TABLE B-1. REVISED CAPITAL COST FACTORS

Pipe + fittings. diameter-in	Cost/unit*	Pipe + fitting, steam traced, & insulated, cost/unit* (1984$)
8	$100/ft	$145/ft
6	$65/ft	$100/ft (153)
4	$50/ft (70)	$83/ft (130)
3	$40/ft (50)	$72/ft (109)
2	$22/ft (30)	$54/ft
1	$15/ft (20)	$46/ft

Valves (3-way lubricated plug valves)

Diameter-in	Cost/unit
8	$3,000
6	$2,500
4	$1,000
3	$ 700
2	$ 500
1	$ 200

Plug valves

8	$1,600
6	$ 900

Pipe supports

Minimum case - $7/ft
Maximum case - $30/ft

Tar decanter clean, cover, and seal

Minimum case - $5/ft^2
Maximum case - $30.5/ft^2

Tar sumps clean, cover, and seal

Minimum case - $10.5/ft^2
Maximum case - $44.5/ft^2

Hot tap

8 in. - $3,800
12 in. - $7,600

Footnote at end of table. (continued)

TABLE B-1. (continued)

Tank sealing

Flushing liquor circulation - \$1,400/tank
Tar tanks - \$1,400/tank

Tank roof (including tank cleanout)

Tar dewatering tank - \$46.5/ft^2
Excess ammonia-liquor tank - \$46.5/ft^2

Vessel sealing

Ammonia-liquor area - \$3,000/unit
Light-oil area - \$1,500/unit

Nitrogen blanketing site preparation

Large plant (assume Model Plant 3 size) - \$30,000/plant

Flame arrestors

6 in - \$2,000/arrestor
4 in - \$1,000/arrestor

Pressure/vacuum relief valves

6 in - \$1,300
4 in - \$800
3 in - \$660

Pressure reducing valve

Valve - \$2,000

Wash-oil scrubber pump

Pump - \$3,900

Wash-oil scrubber instrumentation

Flow, temperature, and pressure - \$2,500

Light-oil sump cover

Minimum case - \$30.5/ft^2
Maximum case - \$164/ft^2

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* Parenthetical numbers refer to light-oil plant cost considering restricted construction conditions, e.g., no welding.

TABLE B-2. REVISED ANNUALIZED COST ITEMS

Item	Cost (1984$)
Benzene credit, as fuel[a]	$0.14/kg
Benzene credit, recovered[a]	$0.39/kg
Light-oil credit[a]	$0.27/kg
Capital recovery (20 yr @ 6.2%)	8.86% of capital
Electricity[b]	$0.05/kWh
Steam[c]	$18.30/Mg
Cooling water[c]	$0.06/m3
Wash oil[d]	$283/$m^3$
Operating labor (including plant overhead @ 80%)[e]	$39.69/h

[a] Derived from Quarterly Coal Report, Energy Information Administration, DOE/EIA-0121, January-March 1984, Table A-16.

[b] Escalated from proposal BID (1982$) 20 percent (electrical rates generally escalated more rapidly than overall rate of inflation).

[c] Escalated from proposal BID (1982$) by 4 percent.

[d] Based on $1.02/gallon + freight (assumed $0.05/gal) per telecon with James Zwikl, Shenango Inc., August 9, 1985.

[e] Based on $22.05 per hour from United Engineers estimates in Bethlehem Steel comments on the proposed regulations, and 80 percent plant overhead rate.

unit cost factors. This procedure resulted in a set of minimum and maximum capital cost estimates for each group of emission sources within each model plant size. These capital cost estimates are shown in Tables B-3 through B-18.

Average capital cost estimates were computed for each group of emission sources and each model plant size by averaging the minimum and coke by-product plants in the industry, equations were developed that estimated the capital costs for each group of emission sources as a function of coke production capacity. An equation best fitting the capital cost estimates for each emission source group and for the three model plant sizes was obtained by performing linear or curvilinear regression analyses on the estimates. Nationwide capital cost estimates was generated by using the equations to estimate the average capital cost for each plant.

Minimum and maximum annualized costs were estimated for each group of emission sources and each model plant size using the unit cost factors in Table B-2 and the capital costs estimated by the above procedure. A set of equations for estimating annualized costs for each emission source group as a function of plant coke production capacity was generated by the same procedure described for capital cost estimates.

Capital recovery charges were computed on the basis of a 20-yr equipment lifetime at 6.2 percent interest. The equipment lifetime was increased from that used in the proposal BID cost estimates to make the equipment lifetime assumption more compatible with typical lifetimes for coke-oven plant equipment in general. The 6.2 percent interest assumption is estimated to be the real (net of inflation) cost of capital to the coke industry.

In the process of estimating nationwide annualized costs, credits for recovery of benzene and/or light oil were applied to all plants except those few specifically identified as not being able to benefit from recovery. The annualized costs are shown in Tables B-3 through B-18.

TABLE B-3. COSTS FOR GAS BLANKETING OF TAR DECANTER, TAR-INTERCEPTING SUMP, AND FLUSHING-LIQUOR CIRCULATION TANK
(All Costs in 1984 Dollars)

	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
Cost element	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Pressure taps	1	1	1	1	1	1	3,800	
20-cm (8-in) pipe, m	61	122	91	244	152	366	476	
(ft)	(200)	(400)	(300)	(800)	(500)	(1,200)	(145)	
7.6-cm (3-in) pipe, m	46	91	46	91	91	183	236	
(ft)	(150)	(300)	(150)	(300)	(300)	(600)	(72)	
Pipe supports, m	107	213	137	335	244	549	23	98.4
(ft)	(350)	(700)	(450)	(1,100)	(800)	(1,800)	(7)	(30)
Valves[b]	4	4	6	6	10	10	3,800	
20-cm (8-in) plug valve	1	1	1	1	1	1	1,600	
Clean, cover, seal decanter,								
m^2	149	149	223	223	446	446	53.8	328
(ft^2)	(1,600)	(1,600)	(2,400)	(2,400)	(4,800)	(4,800)	(5)	30.5
Clean, cover, seal sump,								
m^2	3.0	3.0	23	23	46	46	713	479
(ft^2)	(32)	(32)	(250)	(250)	(500)	(500)	(105)	(44.5)
Seal flushing liquor tanks	1	1	2	2	3	3	1,400	
Capital cost[c]	72,600	172,800	103,100	285,900	176,600	487,500		
Total capital cost[d]	102,300	243,700	145,300	403,200	248,900	687,300		

Footnotes at end of table.

(continued)

TABLE B-3. (continued)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Annualized cost								
Maintenance, overhead (9%)[e]	9,210	21,900	13,100	36,300	22,400	61,900		
Utilities[f]	1,970	3,940	2,740	7,010	4,710	10,900		
Taxes, insurance (4%)	4,090	9,750	5,810	16,100	9,960	27,500		
Capital recovery (8.86%)[g]	9,070	21,600	12,900	35,700	22,000	60,900		
Total annualized cost	24,300	57,200	34,500	95,100	59,100	161,200		

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[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] 3-way valves, 15 cm (6 in)-$2,500; and pressure/vacuum relief valves, 15 cm (6 in)-$1,300.

[c] Capital cost includes subcontractor overhead and profit and contractor material markup.

[d] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[e] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[f] Steam at 18.3/Mg.

[g] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-4. COSTS FOR WASH-OIL VENT SCRUBBER FOR TAR DECANTER, TAR-INTERCEPTING SUMP, AND FLUSHING-LIQUOR CIRCULATION TANK
(All Costs in 1984 Dollars)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Scrubber vessels	4	4	6	6	10	10	1,000	2,000
15.2-cm (6-in) vent pipe,[b] m	46	46	76	76	122	122	351	
(ft)	(150)	(150)	(250)	(250)	(400)	(400)	(107)	
7.6-cm (3-in) vent pipe to sump,[c] m	46	91	46	91	91	183	259	
(ft)	(150)	(300)	(150)	(300)	(300)	(600)	(79)	
2.5-cm (1-in) wash-oil supply, m	61	152	91	610	122	762	49.2	
(ft)	(200)	(500)	(300)	(2,000)	(400)	(2,500)	(15)	
5.1-cm (2-in) wash oil drain,[d] m	61	152	91	610	122	762	95.1	
(ft)	(200)	(500)	(300)	(2,000)	(400)	(2,500)	(29)	
Valves[e]	4	4	6	6	10	10	3,800	
Seal flushing-liquor tanks	1	1	2	2	3	3	1,400	
Clean, cover, and seal tar decanter, m^2	149	149	223	223	446	446	53.8	328.3
(ft^2)	(1,600)	(1,600)	(2,400)	(2,400)	(4,800)	(4,800)	(5)	(30.5)
Clean, cover, and seal tar sumps, m^2	2.97	2.97	23.2	23.2	46.5	46.5	113	479
(ft^2)	(32)	(32)	(250)	(250)	(500)	(500)	(10.5)	(44.5)
Pump	1	1	1	1	2	2	3,900	
Instrumentation[f]	1	1	1	1	2	2	2,500	
Capital cost[g]	68,100	146,900	100,500	270,700	170,600	451,700		
Total capital cost[h]	96,100	207,100	141,700	381,700	240,500	636,800		

Footnotes at end of table.

(continued)

TABLE B-4. (continued)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Annualized costs								
Maintenance, overhead (9%)[i]	8,650	18,600	12,800	34,300	21,600	57,300		
Utilities[j]	1,360	1,790	2,110	2,970	3,700	4,040		
Taxes, insurance (4%)	3,840	8,280	5,670	15,300	9,620	25,500		
Operating labor[k]	7,240	7,240	7,240	7,240	14,500	14,500		
Capital recovery (8.86%)[l]	8,510	18,300	12,600	33,800	21,300	56,400		
Total annualized cost	29,600	54,300	40,300	93,600	70,800	157,700		

[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] Pipe, steam traced @ $328/m or $100/ft and pipe supports @ $23/m or $7/ft.

[c] Pipe @ $236/m or $72/ft and pipe supports @ $23/m or $7/ft.

[d] Pipe @ $72.20/m or $22/ft and pipe supports @ $23/m or $7/ft.

[e] 3-way valves, 15 cm (6-in) - $2,500 and pressure/vacuum release valves, 15 cm (6 in) - $1,300.

[f] Includes flowmeter with alarm, pressure gauge, and temperature gauge.

[g] Capital cost includes subcontractor overhead and profit and contractor or material markup.

[h] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[i] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[j] Electricity at $0.05/kWh.

[k] For 30 min/day/scrubber system at $39.69/h.

[l] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-5. COSTS FOR GAS BLANKETING AMMONIA LIQUOR STORAGE TANKS
(All Costs in 1984 Dollars)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
15.2-cm (6-in) vent pipe, m	46	152	61	183	91	305	328	
(ft)	(150)	(500)	(200)	(600)	(300)	(1,000)	(100)	
Valves[b]	1	1	3	3	6	6	3,800	
15.2-cm (6-in) plug valve	1	1	1	1	1	1	900	
Pipe supports, m	46	152	61	183	91	305	23	98.4
(ft)	(150)	(500)	(200)	(600)	(300)	(1,000)	(7)	(30)
Seal tanks	1	1	3	3	6	6	3,000	
Tank roofs, m^2	0	49.3	0	74.7	0	169	501	
(ft^2)	(0)	(531)	(0)	(804)	(0)	(1,816)	(46.5)	
Capital cost[c]	23,800	97,400	42,700	136,700	73,800	256,100		
Total capital cost[d]	33,500	137,300	60,200	192,700	104,100	361,200		
Annualized costs								
Maintenance, overhead (9%)[e]	3,010	12,300	5,420	17,300	9,370	32,500		
Utilities[f]	870	2,890	1,150	3,460	1,730	5,770		
Taxes, insurance (4%)	1,340	5,490	2,410	7,710	4,160	14,400		
Capital recovery (8.86%)[g]	2,970	12,200	5,330	17,100	9,220	32,000		
Total annualized cost	8,190	32,900	14,300	45,600	24,500	84,700		

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[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] 3-way valves, 15.2 cm (6 in)-$2,500; and pressure/vacuum relief valves, 15.2 cm (6 in)-$1,300.

[c] Capital cost includes subcontractor overhead and profit and contractor material markup.

[d] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[e] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[f] Steam at $18.3/Mg.

[g] Capital recovery factor for a 20-yr lifetime at 6.2%.

TABLE B-6. COSTS FOR WASH-OIL VENT SCRUBBER FOR AMMONIA LIQUOR STORAGE TANKS
(All Costs in 1984 Dollars)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Scrubber vessels	1	1	3	3	6	6	1,000	2,000
7.6-cm (3-in) vent pipe[b], m	9.1	9.1	46	46	91	91	259	
(ft)	(30)	(30)	(150)	(150)	(300)	(300)	(79)	
2.5-cm (1-in) wash-oil line, m	30.5	152	61	152	122	305	49.2	
(ft)	(100)	(500)	(200)	(500)	(400)	(1,000)	(15)	
5.1-cm (2-in.) wash-oil drain,[c] m	30.5	152	61	152	122	305	95.1	
(ft)	(100)	(500)	(200)	(500)	(400)	(1,000)	(29)	
Valves[d]	1	1	3	3	6	6	1,360	
Pumps	0	2	0	2	0	3	3,900	
Instrumentation[e]	1	1	1	1	1	1	1,300	
Seal tanks	1	1	3	3	6	6	3,000	
Tank roofs, m^2	0	49.3	0	74.7	0	169	501	
(ft^2)	(0)	(531)	(0)	(804)	(0)	(1,816)	(46.5)	
Capital cost[f]	14,600	65,700	39,200	100,600	76,000	204,500		
Total capital cost[g]	20,600	92,700	55,300	141,900	107,100	288,400		

Footnotes at end of table.

(continued)

TABLE B-6. (continued)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Annualized costs								
Maintenance, overhead (9%)[h]	1,860	8,340	4,980	12,700	9,640	26,000		
Utilities[i]	92	92	451	451	902	902		
Taxes, insurance (4%)	825	3,710	2,210	5,680	4,280	11,500		
Operating labor[j]	7,240	7,240	7,240	7,240	7,240	7,240		
Capital recovery (8.86%)[k]	1,830	8,210	4,900	12,600	9,490	25,600		
Total annualized cost	11,800	27,600	19,800	38,700	31,600	71,200		

[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] Pipe @ $236/m or $72/ft and pipe supports @ $23/m or $7/ft.

[c] Pipe @ $72.1/m or $22/ft and pipe supports @ $23/m or $7/ft.

[d] 3-way valves, 7.6 cm (3 in)-$700; and pressure/vacuum relief valves, 7.6 cm (3 in)-$660.

[e] Includes flowmeter with alarm, pressure gauge, and temperature gauge.

[f] Capital cost includes subcontractor overhead and profit and contractor material markup.

[g] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[h] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[i] Electricity at $0.05/kWh.

[j] For 30 min/day at $39.69/h.

[k] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-7. COSTS FOR GAS BLANKETING OF LIGHT-OIL CONDENSER, LIGHT-OIL DECANTER, WASH-OIL DECANTER, AND CIRCULATION TANK
(All Costs in 1984 Dollars)

	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
Cost element	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Pressure tap	1	1	1	1	1	1	3,800	
10- to 15-cm (4- to 6-in)								
pipe,[b] m	61	183	122	244	183	305	483.1	
(ft)	(200)	(600)	(400)	(800)	(600)	(1,000)	(147.25)	
Plug valve, 15 cm (6 in)	1	1	1	1	1	1	900	
Valves[c]	6	6	8	8	13	13	1,800	
Seal vessels	6	6	8	8	13	13	1,500	
Flame arrestors	6	6	8	8	13	13	1,000	
Capital cost[d]	60,000	118,900	98,000	156,900	149,000	207,900		
Total capital cost[e]	84,500	167,600	138,200	221,200	210,000	293,100		
Annualized costs								
Maintenance, overhead (9%)[f]	7,600	15,100	12,400	19,900	18,900	26,400		
Utilities[g]	1,100	3,200	2,100	4,200	3,200	5,300		
Taxes, insurance (4%)	3,400	6,700	5,500	8,800	8,400	11,700		
Capital recovery (8.86%)[h]	7,500	14,800	12,200	19,600	18,600	26,000		
Total annualized cost	19,500	39,800	32,300	52,600	49,100	69,300		

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[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] Assumes 75% of pipe is 15-cm (6-in) header and 25% is 10-cm (3-in) vent lines.

[c] 3-way valves, 10.2 cm (4 in)-$1,000; and pressure/vacuum relief valves, 10.2 cm (4 in)-$800.

[d] Capital cost includes subcontractor overhead and profit and contractor material markup.

[e] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[f] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[g] Steam at $18.3/Mg.

[h] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-8. COSTS OF WASH-OIL VENT SCRUBBER FOR LIGHT-OIL CONDENSER, LIGHT-OIL DECANTERS, WASH-OIL DECANTERS, AND CIRCULATION TANKS
(All Costs in 1984 Dollars)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Scrubber vessels	6	6	8	8	13	13	1,000	2,000
10.2-cm (4-in) vent pipe,[b] m	110	110	146	146	238	238	449.5	
(ft)	(360)	(360)	(480)	(480)	(780)	(780)	(137)	
2.5-cm (1-in) wash-oil supply pipe, m	30.5	122	91.4	244	122	305	65.6	
(ft)	(100)	(400)	(300)	(800)	(400)	(1,000)	(20)	
5.1-cm (2-in) wash-oil drain pipe,[c] m	30.5	122	91.4	244	122	305	121.4	
(ft)	(100)	(400)	(300)	(800)	(400)	(1,000)	(37)	
Valves[d]	6	6	8	8	13	13	1,800	
Seal vessels	6	6	8	8	13	13	1,500	
Pump	0	2	0	2	0	4	3,900	
Instrumentation[e]	1	1	1	1	2	2	2,500	
Capital cost[f]	83,300	114,200	119,800	164,100	190,600	253,400		
Total capital cost[g]	117,500	161,100	168,900	231,300	268,700	357,200		

Footnotes at end of table.

(continued)

TABLE B-8. (continued)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Annualized costs								
Maintenance, overhead (9%)[h]	10,600	14,500	15,200	20,800	24,200	32,200		
Utilities[i]	1,400	1,400	1,920	1,920	3,170	3,170		
Taxes, insurance (4%)	7,700	6,440	6,750	9,250	10,700	14,300		
Operating labor[j]	7,240	7,240	7,240	7,240	14,500	14,500		
Capital recovery (8.86%)[k]	10,400	14,300	15,000	20,500	23,800	31,700		
Total annualized cost	34,300	43,900	46,100	59,700	76,400	95,800		

[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] Pipe, steam traced @ $426.5/m or $130/ft and pipe supports @ $23/m or $7/ft.

[c] Pipe @ $98.4/m or $30/ft and pipe supports @ $23/m or $7/ft.

[d] 3-way valves, 10.2 cm (4 in)-$1,000; and pressure/vacuum relief valves, 10.2 cm (4 in)-$800.

[e] Includes flowmeter with alarm, pressure gauge, and temperature gauge.

[f] Capital cost includes subcontractor overhead and profit and contractor material markup.

[g] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[h] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[i] Steam at $18.3/Mg and electricity at $0.05/kWh.

[j] For 30 min/day/scrubber system at $39.69/h.

[k] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-9. COSTS FOR GAS BLANKETING OF LIGHT-OIL AND BTX STORAGE TANKS
(All Costs in 1984 Dollars)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
10- to 15-cm (4- to 6-in)	49	183	61	259	122	335	483.1	
pipe,[b] m	(160)	(600)	(200)	(850)	(400)	(1,100)	(147.25)	
(ft)	4	4	9	9	15	15	1,800	
Pipe supports, m	49	183	61	259	122	335	23	98.4
(ft)	(160)	(600)	(200)	(850)	(400)	(1,100)	(7)	(30)
Seal tanks	4	4	9	9	15	15	1,500	
Flame arrestors	4	4	9	9	15	15	1,000	
Capital cost[d]	41,900	123,600	69,600	189,400	126,200	259,500		
Total capital cost[e]	59,100	174,200	98,100	267,000	177,900	365,900		
Annualized costs								
Maintenance, overhead (9%)[f]	5,320	15,700	8,830	24,000	16,000	32,900		
Utilities[g]	850	3,170	1,060	4,490	2,110	5,810		
Taxes, insurance (4%)	2,360	6,970	3,920	10,700	7,120	14,600		
Capital recovery (8.86%)[h]	5,230	15,400	8,690	23,700	15,800	32,400		
Total annualized cost	13,800	41,300	22,500	62,900	41,000	85,800		

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[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] Assumes 75% of pipe is 15-cm (6-in) header and 25% is 10-cm (3-in) vent lines.

[c] 3-way valves, 10.2 cm (4 in) - $1,000; and pressure/vacuum relief valves, 10.2 cm. (4 in) - $800.

[d] Capital cost includes subcontractor overhead and profit and contractor markup.

[e] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[f] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[g] Steam at $18.3/Mg.

[h] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-10. COSTS OF WASH-OIL VENT SCRUBBER FOR LIGHT-OIL AND BTX STORAGE TANKS
(All Costs in 1984 Dollars)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Scrubber vessels	4	4	9	9	15	15	1,000	2,000
10-cm (4-in) vent pipe[b], m	61	61	137	137	229	229	449.5	
(ft)	(200)	(200)	(450)	(450)	(750)	(750)	(137)	
2.5-cm (1-in) wash-oil line, m	30.5	183	30.5	213	61	244		
(ft)	(100)	(600)	(100)	(700)	(200)	(800)	(20)	
5.1-cm (2-in) wash-oil drain,[c] m	30.5	183	30.5	213	61	244		
(ft)	(100)	(600)	(100)	(700)	(200)	(800)	(37)	
Pumps	0	2	0	2	0	4	3,900	
Valves[d]	4	4	9	9	15	15	1,800	
Vessel sealing	4	4	9	9	15	15	1,500	
Instrumentation[e]	1	1	1	1	2	2	2,500	
Capital cost[f]	52,800	93,100	108,600	159,600	183,700	248,500		
Total capital cost[g]	74,400	131,300	153,100	225,000	258,900	350,300		

Footnotes at end of table.

(continued)

TABLE B-10. (continued)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Annualized costs								
Maintenance, overhead (9%)[h]	6,700	11,800	13,800	20,200	23,300	31,500		
Utilities[i]	794	794	1,800	1,800	2,980	2,980		
Taxes, insurance (4%)	2,980	5,250	6,120	9,000	10,400	14,000		
Operating labor[j]	7,240	7,240	7,240	7,240	14,500	14,500		
Capital recovery (8.86%)[k]	6,600	11,600	13,600	19,900	22,900	31,000		
Total annualized cost	24,300	36,700	42,500	58,200	74,100	94,000		

[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] Pipe @ $426.5/m or $130/ft and pipe supports @ $23/m or $7/ft.

[c] Pipe @ $98.4/m or $30/ft and pipe supports @ $23/m or $7/ft.

[d] 3-way valves, 10.2 cm (4 in) - $1,000; pressure/vacuum relief valves, 10.2 cm (4-in) - $800.

[e] Includes flowmeter with alarm, pressure gauge, and temperature gauge.

[f] Capital cost includes subcontractor overhead and profit and contractor material markup.

[g] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[h] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[i] Steam at $18.3/Mg and electricity at $0.05/kWh.

[j] For 30 min/day/scrubber system at $39.69/h.

[k] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-11. COSTS FOR GAS BLANKETING OF TAR COLLECTING, STORAGE, AND DEWATERING TANKS
(All Costs in 1984 Dollars)

	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
Cost element	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
15-cm (6-in) pipe, m	61	152	91	762	122	914	328.1	
(ft)	(200)	(500)	(300)	(2,500)	(400)	(3,000)	(100)	
Seal tanks	5	5	10	10	16	16	1,400	
Tank roofs-dewatering, m^2	0	49	0	75	0	169	500.5	
(ft^2)	(0)	(531)	(0)	(804)	(0)	(1,816)	(46.5)	
Pipe supports, m	61	152	91	762	122	914	23	98.4
(ft)	(200)	(500)	(300)	(2,500)	(400)	(3,000)	(7)	(30)
Valves[b]	5	5	10	10	16	16	3,800	
Capital cost[c]	47,400	115,700	84.100	414,400	126,000	557,600		
Total capital cost[d]	66,800	163,100	118,600	584,300	177,700	786,300		
Annualized costs								
Maintenance, overhead (9%)[e]	6,020	14,700	10,700	52,600	16,000	70,800		
Utilities[f]	1,150	2,880	1,730	14,400	2,310	17,300		
Taxes, insurance (4%)	2,670	6,530	4,740	23,400	7,110	31,500		
Capital recovery (8.86%)[g]	5,920	14,500	10,500	51,800	15,700	69,700		
Total annualized cost	15,800	38,500	27,700	142,100	41,100	189,200		

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[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] From Table B-1, 3-way valves, 15 cm (6 in) - \$2,500; pressure/vacuum relief valves, 15 cm (6 in) - \$1,300

[c] Capital cost includes subcontractors overhead and profit and contractor material markup.

[d] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[e] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[f] Steam at \$18.3/Mg.

[g] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-12. COSTS OF WASH-OIL VENT SCRUBBER FOR TAR COLLECTING, STORAGE, AND DEWATERING TANKS
(All Costs in 1984 Dollars)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Scrubber, heat exchanger, separator	62,700	62,700	144,000	144,000	234,000	234,000		
15.2-cm (6-in) vent pipe,[b] m	122	122	244	244	390	390	351	
(ft)	(400)	(400)	(800)	(800)	(1,280)	(1,280)	(107)	
10.2-cm (4-in) wastewater pipe, m	30.5	61	30.5	61	30.5	61	272.3	
(ft)	(100)	(200)	(100)	(200)	(100)	(200)	(83)	
2.5-cm (1-in) wash oil supply pipe, m	30.5	152	91.4	640	122	853	49.2	
(ft)	(100)	(500)	(300)	(2,100)	(400)	(2,800)	(15)	
5.1-cm (2-in) wash oil drain pipe,[c] m	30.5	152	91.4	640	122	853	95.1	
(ft)	(100)	(500)	(300)	(2,100)	(400)	(2,800)	(29)	
Seal tank	5	5	10	10	16	16	1,400	
Tank roofs, dewatering, m^2	0	49.3	0	74.7	0	169	500.5	
(ft^2)	(0)	(531)	(0)	(804)	(0)	(1,816)	(46.5)	
Pump	1	1	1	1	2	2	11,000	
Valves[d]	5	5	10	10	16	16	3,800	
Valves and level control	1	1	1	1	2	2	2,000	
Instrumentation[e]	1	1	1	1	2	2	2,500	
Capital cost[f]	159,700	210,300	318,600	443,500	511,100	709,400		
Total capital cost[g]	225,200	296,500	449,200	625,300	720,600	1,000,300		

(continued)

Footnotes at end of table.

TABLE B-12. (Continued)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Annualized costs								
Maintenance, overhead (9%)[h]	20,300	26,700	40,400	56,300	64,900	90,000		
Utilities[i]	9,890	10,300	33,700	34,100	72,400	72,800		
Taxes, insurance	9,000	11,900	18,000	25,000	28,800	40,000		
Operating labor[j]	7,240	7,240	7,240	7,240	14,500	14,500		
Capital recovery[k]	20,000	26,300	39,800	55,400	63,800	88,600		
Total annualized cost	66,400	82,300	139,200	178,100	244,400	305,900		

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[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] Pipe, steam traced @ $328/m or $100/ft and pipe supports @ $23/m or $7/ft.

[c] Pipe @ $72.20/m or $22/ft and pipe supports @ $23/m or $7/ft.

[d] 3-way valves, 15 cm (6 in)-$2,500, pressure/vacuum release valves, 15 cm (6 in)-$1,300.

[e] Includes flowmeter with alarm, pressure gauge, and temperature gauge.

[f] Capital cost includes subcontractor overhead and profit and contractor material markup.

[g] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[h] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[i] Steam at $18.3/Mg and electricity at $0.05/kWh.

[j] For 30 min/day/scrubber system at $39.69/h.

[k] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-13. COSTS FOR COVERING LIGHT-OIL SUMP
(All Costs in 1984 Dollars)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Clean, cover, and seal, m^2	3.3	20.9	3.3	93	6.7	186	328	1,765
(ft^2)	(36)	(225)	(36)	(1,000)	(72)	(2,000)	(30.5)	(164)
7.6-cm (3-in) vent pipe, m	4.6	4.6	4.6	4.6	9.1	9.1	131	
(ft)	(15)	(15)	(15)	(15)	(30)	(30)	(40)	
Capital cost[b]	1,700	37,500	1,700	164,600	3,400	329.200		
Total capital cost[c]	2,390	52,900	2,390	232,100	4,790	464,200		
Annualized costs								
Maintenance, overhead (9%)[d]	215	4,760	215	20,900	431	41,800		
Taxes, insurance (4%)	96	2,120	96	9,280	192	18,600		
Capital recovery (8.86%)[e]	212	4,690	212	20,600	424	41,100		
Total annualized cost	523	11,600	523	50,700	1,050	101,500		

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[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] Capital cost includes subcontractor overhead and profit and contractor material markup.

[c] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[d] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[e] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-14. COSTS FOR NITROGEN OR NATURAL GAS BLANKETING OF PURE BENZENE STORAGE TANKS (All Costs in 1984 Dollars)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
2.5-cm (1-in) gas supply,[b] m	12.2	30.5	30.5	91.4	61	213	(88.6)	
(ft)	(40)	(100)	(100)	(300)	(200)	(700)	(27)	
7.6-cm (3-in) vent pipe, m	15.2	91.4	30.5	152	61	244	164	
(ft)	(50)	(300)	(100)	(500)	(200)	(800)	(50)	
Pressure controller	1	1	1	1	1	1	4,400	
Pressure reducers	2	2	2	2	2	2	2,000	
Site preparation	0	8,000	0	18,400	0	30,000		
10.2-cm (4-in) flame arrestors	1	1	3	3	7	7	1,000	
Valves[c]	1	1	3	3	7	7	1,360	
Tank sealing	1	1	3	3	7	7	1,400	
Pipe supports, m	15.2	91.4	30.5	152	61	244	23	98.4
(ft)	(50)	(300)	(100)	(500)	(200)	(800)	(7)	(30)
Capital costs[d]	16,100	46,900	28,100	86,200	51,500	147,600		
Total capital costs[e]	22,700	66,100	39,600	121,500	72,600	208,100		
Annualized costs								
Maintenance, overhead (9%)[f]	2,040	5,950	3,560	10,900	6,540	18,700		
Utilities[g]	0	1,700	0	6,700	0	15,000		
Taxes, insurance (4%)	910	2,640	1,580	4,860	2,910	8,330		
Operating labor[h]	0	7,240	0	7,240	0	7,240		
Capital recovery (8.86%)[i]	2,010	5,860	3,510	10,800	6,440	18,400		
Total annualized cost	4,960	23,400	8,650	40,500	15,900	67,700		

Footnotes at end of table.

(continued)

TABLE B-14. (continued)

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[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] Includes pipe supports at \$23/m (\$7/ft).

[c] 3-way valves, 7.6 cm (3 in)-\$700; and pressure/vacuum relief valves, 7.6 cm (3 in)-\$660.

[d] Capital cost includes subcontractor overhead and profit and contractor material markup.

[e] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[f] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[g] Nitrogen at \$0.27/m^3 (0.76/100 ft^3). Includes rental of 5.7-m^3 (1,500-gal) liquid nitrogen storage tank, vaporizer, and gas usage. Some plants are assumed to have a nitrogen source and others must purchase nitrogen.

[h] For 30 min/day at \$39.69/h when liquid nitrogen is used.

[i] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-15. COSTS OF WASH-OIL VENT SCRUBBER FOR BENZENE STORAGE TANKS
(All Costs in 1984 Dollars)

Cost element	Model plant 1		Model plant 2		Model plant 3		Cost per unit[a]	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Scrubber vessels	1	1	3	3	7	7	1,000	2,000
2.5-cm (1-in) wash-oil line, m	30.5	183	30.5	213	61	244	65.6	
(ft)	(100)	(600)	(100)	(700)	(200)	(800)	(20)	
5.1-cm (2-in.) wash-oil drain,[b] m	30.5	183	30.5	213	61	244	121.4	
(ft)	(100)	(600)	(100)	(700)	(200)	(800)	(37)	
Pump	0	1	0	2	0	2	3,900	
10-cm (4-in) vent pipe[c], m	15.2	15.2	45.7	45.7	107	107	252.6	
(ft)	50	50	150	(150)	(350)	(350)	(77)	
Valves[d]	1	1	3	3	7	7	1,800	
10.2-cm (4-in) flame arrestors	1	1	3	3	7	7	1,000	
Tank sealing	1	1	3	3	7	7	1,400	
Instrumentation[e]	1	1	1	1	1	1	2,500	
Capital cost[f]	17,300	50,700	35,400	80,400	77,300	126,300		
Total capital costs[g]	24,300	71,400	49,800	113,300	108,900	178,000		
Annualized costs								
Maintenance, overhead (9%)[h]	2,190	6,430	4,490	10,200	9,800	16,000		
Utilities[i]	6	6	19	19	43	43		
Taxes, insurance (4%)	973	2,860	1,990	4,530	4,360	7,120		
Operating labor[j]	7,240	7,240	7,240	7,240	7,240	7,240		
Capital recovery (16.3%)[k]	2,160	6,330	4,420	10,040	9,650	15,800		
Total annualized cost	12,600	22,900	18,200	32,000	31,100	46,200		

Footnotes at end of table.

(continued)

TABLE B-15. (continued)

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[a] Where a range of unit costs was used, the high and low values are shown as maximum and minimum; where only a single value was used, it is shown in the minimum column.

[b] Pipe @ 98.4/m or $30/ft and pipe supports @ $23/m or $7/ft.

[c] Pipe @ $229.6/m or $70/ft and pipe supports @ $23/m or $7/ft.

[d] 3-way valves, 10.2 cm (4 in)-$1,000; and pressure/vacuum relief valves, 10.2 cm (4 in)-$800.

[e] Includes flowmeter with alarm, pressure gauge, and temperature gauge.

[f] Capital cost includes subcontractor overhead and profit and contractor or material markup.

[g] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[h] Maintenance and overhead are 5% and 4% of capital, respectively.

[i] Electricity at $0.05/kWh.

[j] For 30 min/day at $39.69/h.

[k] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-16. COSTS FOR TAR BOTTOM FINAL COOLER
(All Costs in 1984 Dollars)

Cost element	Model plant 1		Model plant 2		Model plant 3	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Tank-separator, decanter tank, wastewater tank, and tar tank	61,700	61,700	141,700	141,700	230,500	230,500
Pumps - tar transfer, water skimmer	16,300	16,300	26,600	26,600	37,800	37,800
Piping and valves	26,800	82,800	80,100	247,700	152,000	470,000
Site preparation, modify existing cooler, miscellaneous	31,700	31,700	72,800	72,800	118,400	118,400
Instrumentation (6.75% of equipment)	7,070	10,800	16,800	28,100	28,400	49,800
Electrical (10.5% of equipment)	11,000	16,900	26,100	43,700	44,100	77,500
Capital cost[a]	154,500	220,100	363,900	560,500	611,100	984,000
Total capital cost[b]	217,800	310,400	513,200	790,200	861,700	1,387,400
Annualized cost						
Maintenance, overhead (9%)[c]	19,600	27,900	46,200	71,100	77,600	124,900
Utilities[d]	2,200	5,040	7,590	16,000	16,200	32,300
Taxes, insurance (4%)	8,710	12,400	20,500	31,600	34,500	55,500
Operating labor[e]	22,000	22,000	22,000	22,000	22,000	22,000
Capital recovery (8.86%)[f]	19,300	27,500	45,500	70,000	76,300	122,900
Total annualized cost	71,800	94,900	141,800	210,800	226,600	357,500

[a] Capital cost includes subcontractor overhead and profit and contractor material markup.

[b] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[c] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[d] Steam at $18.3/Mg and electricity at $0.05 kWh.

[e] For 1.5 h/day at $39.69/h.

[f] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-17. COSTS FOR WASH-OIL FINAL COOLER
(All Costs in 1984 Dollars)

Cost element	Model plant 1	Model plant 2	Model plant 3
Final cooler	708,000	1,627,000	2,646,000
Instrumentation (6.75% of final cooler capital cost)	47,800	109,800	178,600
Electrical (10.5% of final cooler capital cost)	74,300	170,800	277,800
Capital cost[a]	830,100	1,908,000	3,102,000
Total capital cost[b]	1,171,000	2,690,000	4,374,000
Annualized costs			
Maintenance, overhead (9%)[c]	105,400	242,100	393,700
Utilities[d]	46,200	184,900	416,100
Makeup wash oil[e]	7,600	30,500	68,500
Taxes, insurance (4%)	46,800	107,600	175,000
Operating labor[f]	69,000	69,000	69,000
Capital recovery (8.86%)[g]	103,700	238,300	387,600
Total annualized cost	378,700	872,400	1,509,900

[a] Capital cost includes subcontractor overhead and profit and contractor material markup.

[b] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[c] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[d] Steam at $18.3/Mg and electricity at $0.05/kWh.

[e] Estimated at $0.34/kg ($1.07/gal); based on losses to wastewater and light-oil crude residue.

[f] For 4.8 h/day at $39.69/h.

[g] Capital recovery factor for 20-yr lifetime at 6.2%.

TABLE B-18. COSTS OF MIXER-SETTLER FOR NAPHTHALENE PROCESSING AND HANDLING
(All Costs in 1984 Dollars)

Cost element	Model plant 1		Model olant 2		Model plant 3	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Tank-separator, decanter tank, wastewater tank, and tar tank	61,700	61,700	141,700	141,700	230,500	230,500
Pumps - tar transfer, water skimmer	16,300	16,300	26,600	26,600	37,800	37,800
Piping and valves	26,800	82,800	80,100	247,700	152,000	470,000
Site preparation, modify existing cooler, miscellaneous	31,700	31,700	72,800	72,800	118,400	118,400
Instrumentation (6.75% of equipment)	7,070	10,800	16,800	28,100	28,400	49,800
Electrical (10.5% of equipment)	11,000	16,900	26,100	43,700	44,100	77,500
Capital cost[a]	154,500	220,100	363,900	560,500	611,100	984,000
Total capital cost[b]	217,800	310,400	513,200	790,200	861,700	1,387,400
Annualized cost						
Maintenance, overhead (9%)[c]	19,600	27,900	46,200	71,100	77,600	124,900
Utilities[d]	2,200	5,040	7,590	16,000	16,200	32,300
Taxes, insurance (4%)	8,710	12,400	20,500	31,600	34,500	55,500
Operating labor[e]	22,000	22,000	22,000	22,000	22,000	22,000
Capital recovery (8.86%)[f]	19,300	27,500	45,500	70,000	76,300	122,900
Total annualized cost	71,800	94,900	141,800	210,800	226,600	357,500

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[a] Capital cost includes subcontract or overhead and profit and contractor or material markup.

[b] Total capital cost includes construction fee, contingency, engineering, and startup (41%).

[c] Maintenance and overhead are 5% and 4% of total capital cost, respectively.

[d] Steam at $18.3/Mg and electricity at $0.05 kWh.

[e] For 1.5 h/day at $39.69/h.

[f] Capital recovery factor for 20-yr lifetime at 6.2%

Appendix C

Economic Impact Analysis

APPENDIX C

ECONOMIC IMPACT

This appendix addresses the economic impacts of the regulatory alternatives for coke-oven by-product plants. It provides an updated version of Chapter 9 of the background information document (BID), Benzene Emissions from Coke By-Product Recovery Plants. This appendix includes revised estimates of the economic impacts of the regulatory alternatives and more recent information on the state of the coke industry. Where possible, data are updated to 1984.

Section C.1 presents a profile of the coke industry. Section C.2 contains a reanalysis of the impacts of the regulatory alternatives. These alternatives are outlined in Table C-1. These impacts are measured against the baseline state of control for all sources. Section C.3 presents potential socioeconomic and inflationary impacts.

C.1 INDUSTRY PROFILE

C.1.1 Introduction

Coke production is a part of Standard Industrial Code (SIC) 3312--Blast Furnaces and Steel Mills. Coke is principally used in the production of steel and ferrous foundry products, which are also part of the output of SIC 3312. Thus, coke is both produced and principally consumed within SIC 3312. Furthermore, many producers of furnace coke are fully integrated iron- and steel-producing companies. Any regulation on coke production is expected to have some impact on the entire blast furnaces and steel mills industry with special emphasis on coke producers.

This profile has two purposes: (1) to provide the reader with a broad overview of the industry and (2) to lend support to an economic analysis by assessing the appropriateness of various economic models to analyze the

TABLE C-1. COKE BY-PRODUCT PLANT CONTROL OPTIONS[a]

	Control option	
Emission source	Regulatory Alternative II	Regulatory Alternative III
Direct water final cooler	Tar bottom final cooler	Wash-oil final cooler
Tar bottom final cooler		Wash-oil final cooler
Tar decanter, flushing-liquor circulation tank, tar-intercepting sump	Coke-oven gas-blanketing system	Coke-oven gas-blanketing system
Tar storage tanks and dewatering tanks	Coke-oven gas-blanketing system	Coke-oven gas-blanketing system
Light-oil decanter-condenser, wash-oil circulation tank, wash-oil decanter	Coke-oven gas-blanketing system	Coke-oven gas-blanketing system
Excess ammonia-liquor storage tanks	Coke-oven gas-blanketing system	Coke-oven gas-blanketing system
Light-oil tanks and BTX storage tanks	Coke-oven gas-blanketing system	Coke-oven gas-blanketing system
Benzene storage tanks	Wash-oil scrubber	Wash-oil scrubber
Light-oil sump	Cover	Cover
Pump seal leaks	Monthly inspection	Monthly inspection
Valve leaks	Monthly inspection	Monthly inspection
Exhauster leaks	Quarterly inspection	Quarterly inspection
Pressure relief device leaks	Rupture disc system	Rupture disc system
Sampling connection system leaks	Closed-purge system	Closed-purge system
Open-ended line leaks	Cap or plug	Cap or plug

[a] These regulatory alternative control options differ from the proposed regulations.

industry. Further, the profile provides some of the data necessary to the analysis itself.

The industry profile comprises six major sections. The remainder of this introduction, which constitutes the first section, provides a brief, descriptive, and largely qualitative look at the industry. The remaining five sections of the profile conform with a particular model of industrial organizational analysis. This model maintains that an industry can be characterized by its basic conditions, market structure, market conduct, and market performance.

The basic conditions in the industry, discussed in the second and third sections of this profile, are believed to be major determinants of the prevailing market structure. Most important of these basic conditions are supply conditions, which are largely technological in nature, and demand conditions, which are determined by the attributes of the products themselves.

The market structure and market conduct of the blast furnaces and steel mills industry are examined in the fourth section. Issues addressed include geographic concentration, firm concentration, integration, and barriers to entry. Market structure is believed to have a major influence on the conduct of market participants. Market conduct is the price and nonprice behavior of sellers. Of particular interest is the degree to which the industry pricing behavior can be approximated by the competitive pricing model, the monopoly pricing model, or some model of imperfect competition.

The fifth section of the industry profile addresses market performance. The historical record of the industry's financial performance is examined, with some emphasis on its comparison with other industries. The sixth section of the industry profile presents a discussion of industry trends for the coke and steel sectors. The seventh section discusses market behavior.

C.1.1.1 Definition of the Coke Industry. Coke production is a part of SIC 3312--Blast Furnaces and Steel Mills, which includes establishments that produce coke and those that primarily manufacture hot metal, pig iron, silvery pig iron, and ferroalloys from iron ore and iron and steel scrap.

Establishments that produce steel from pig iron, iron scrap, and steel scrap and establishments that produce basic shapes such as plates, sheets, and bars by hot rolling the iron and steel also are included in SIC 3312.[1] The total value of shipments from SIC 3312 in 1982 was $36,931,900,000[2] and an approximate value for total coke production in 1982 was $3,220,011,000,[3] or less than 10 percent of the total value of shipments.

Coke is produced in two types of plants: merchant and captive. Merchant plants produce coke to be sold on the open market, and many are owned by chemical or other companies. The majority of coke plants in the United States are captive plants that are vertically integrated with iron and steel companies and use coke in the production of pig iron. At the end of 1984, 15 plants were merchant and 36 were captive, and merchant plants accounted for only 12 percent of total coke production.[4] [5] For the economic analysis, it is assumed that more than one plant may exist at a single location.

C.1.1.2 Brief History of the Coke Industry in the Overall Economy. Traditionally, the value of coke produced in the United States has constituted less than 1 percent of the gross national product (GNP).[6] [7] During most of the 1950's, coke production was about 0.30 percent of GNP, and during the 1960's and until the mid-1970's, coke production was only about 0.20 percent or less of GNP. However, in 1974, coke production as a percent of GNP rose to above 0.30 percent. This trend continued for the next 2 years. By 1982, coke production was about 0.1 percent of GNP.[3] [8]

Previously, U.S. coke exports had been greater than imports, but that trend has fluctuated. The values of all U.S. imports and exports and U.S. coke imports and exports are shown in Table C-2. From 1950 to 1972, coke exports were much greater than coke imports, but after 1973, this trend was reversed. In 1982 and 1983, exports again exceeded imports. Data for the second quarter of 1984 indicate that coke imports are again on the rise. Imports for the first two quarters of 1984 totaled 247,604 megagrams (Mg) compared to 6,874 Mg for the same period in 1983, and to 32,000 Mg for all of 1983.[16] Exports for the first two quarters of 1984 and 1983 were 307,540 Mg, and 300,283 Mg, respectively, and they were 603,288 Mg for all of 1983.[16]

TABLE C-2. COKE INDUSTRY FOREIGN TRADE[a] 9 10 11 12 13 14 15

Year	Total U.S. imports, 10^9 \$[a]	Coke imports for consumption, 10^6 \$[a]	Coke imports as a share of total imports, %	U.S. exports, 10^9 \$[a]	Coke exports, 10^6 \$[a]	Coke exports as a share of total exports, %
1950	8.9	5.3	0.06	10.3	6.2	0.06
1951	11.0	1.9	0.02	15.0	17.7	0.12
1952	10.7	4.5	0.04	15.2	13.7	0.09
1953	10.9	1.7	0.02	15.8	9.3	0.06
1954	10.2	1.3	0.01	15.1	6.2	0.04
1955	11.4	1.4	0.01	15.5	8.2	0.05
1956	12.6	1.5	0.01	19.1	11.5	0.06
1957	13.0	1.5	0.01	20.9	14.4	0.07
1958	12.8	1.6	0.01	17.9	7.1	0.04
1959	15.2	1.4	0.01	17.6	8.7	0.05
1960	14.7	1.5	0.01	20.6	6.9	0.03
1961	14.7	1.5	0.01	21.0	8.2	0.04
1962	16.4	1.9	0.01	21.7	7.4	0.03
1963	17.1	2.0	0.01	23.3	8.3	0.04
1964	18.7	1.5	0.01	26.5	10.1	0.04
1965	21.4	1.4	0.01	27.5	16.3	0.06
1966	25.5	1.8	0.01	30.3	23.4	0.08
1967	26.8	1.7	0.01	31.5	16.5	0.05
1968	33.2	1.9	0.01	34.6	18.6	0.05
1969	36.0	3.4	0.01	38.0	38.5	0.10
1970	39.9	3.5	0.01	42.5	78.9	0.19
1971	45.6	5.0	0.01	43.5	44.8	0.10
1972	55.8	4.6	0.01	49.4	30.7	0.06
1973	70.5	39.3	0.06	71.4	33.1	0.05
1974	103.7	193.2	0.19	98.3	43.6	0.04
1975	98.0	156.5	0.16	107.1	74.7	0.07
1976	124.0	111.1	0.09	114.7	66.7	0.06
1977	151.9	137.9[b]	0.09	120.8	71.9[b,c]	0.06
1978	176.0	410.9[b]	0.23	142.1	68.9[b,d]	0.05
1979	212.0	340.1[b]	0.16	184.5	15.0[b]	0.01
1980	249.7	52.0[b]	0.02	224.2	12.9[b]	0.005
1981	265.1	54.0[b,e]	0.02	237.0	11.3[b]	0.005
1982	243.9	9.2[b]	0.004	212.3	13.8[b]	0.01
1983	258.0	1.9[b]	0.0007	200.5	8.3[b]	0.004

[a] Current dollars.

[b] See Product SIC (331210) in References 11-13.

[c] Defined as "Pitch coke, coke of coal, lignite, or peat."

[d] Defined as "Coal coke, calcined and not calcined."

[e] Cumulative through November 1981. Annual cumulative value not available.

The same pattern applies to the percentages of coke imports and exports within total U.S. imports and exports. From 1950 to 1972, coke exports were a larger percentage of total U.S. exports than coke imports were of total U.S. imports. Again, from 1973 to 1981, this trend reversed, and coke imports were a larger proportion of total U.S. imports than coke exports were of total U.S. exports. Percentage shares of exports were greater than imports in 1982 and 1983.

U.S. coke production always has been a substantial portion of world coke production. This share has decreased during the past 30 years, as indicated in Table C-3. From 1950 to 1977, world coke production generally increased while U.S. coke production decreased. This trend explains the decline in the U.S. percentage of world coke production.

C.1.1.3 Size of the Iron and Steel Industry. The value of shipments of SIC 3312 has increased since 1960. There have been a few fluctuations in this growth; for example, as shown in Table C-4, the 1965 value of shipments of SIC 3312 was the highest value between 1960 and 1972. Since 1972, the value of shipments has remained around $30 million, with the highest value being $35 million (1972 dollars) in 1974. After reaching another peak of $34 million (1972 dollars), the value of shipments declined to a 23-year low of about $18 million (1972 dollars). This result reflected conditions in the steel industry. In 1982, the steel industry sustained record financial losses close to $3.2 billion (1982 dollars).[23] In 1983, an additional $3.6 billion was lost.[24]

For SIC 3312, Table C-5 shows the value added by manufacture, the total number of employees, and the value added per employee. Current and constant (1972) dollar figures are included. Both the total value added by manufacture and the value added per employee peaked in 1974, the same year in which the value of shipments for this industry was the highest. The increasing value added per employee might indicate that this industry is changing to a more capital-intensive production process. This aspect is discussed in Section C.1.6.

C.1.2 Production

C.1.2.1 Product Description. Two types of coke are produced: furnace coke and foundry coke. Furnace coke is used as a fuel in blast furnaces;

TABLE C-3. COKE PRODUCTION IN THE WORLD[6] [17] [18]

Year	World production,[a] 10^6 Mg	U.S. production, 10^6 Mg	U.S. production as a share of world production, %
1950	182.3	65.9	36.1
1951	204.1	71.9	35.2
1952	208.9	62.0	29.7
1953	225.6	71.5	31.7
1954	211.5	54.4	25.7
1955	242.3	68.3	28.2
1956	256.8	67.6	26.3
1957	266.1	69.0	25.9
1958	255.0	48.6	19.1
1959	260.4	50.7	19.5
1960	279.7	51.9	18.6
1961	272.0	46.9	17.2
1962	272.9	47.1	17.3
1963	281.7	49.3	17.5
1964	298.5	56.4	18.9
1965	310.3	60.7	19.6
1966	310.4	61.2	19.7
1967	303.9	58.6	19.3
1968	315.8	57.8	18.3
1969	335.8	58.8	17.5
1970	350.5	60.3	17.2
1971	342.7	52.1	15.2
1972	340.5	54.9	16.1
1973	365.8	58.4	16.0
1974	367.4	55.9	15.2
1975	363.3	51.9	14.3
1976	367.2	52.9	14.4
1977	373.5	48.5	13.0
1978	364.7	44.5	12.2
1979[b]	341.0	48.0	14.1

[a] Oven and beehive coke combined.

[b] Information on world coke production not available after 1979.

TABLE C-4. VALUE OF SHIPMENTS, SIC 3312[2] [19] [20] [21] [22]

Year	Current dollars, 10^6	1972 Dollars, 10^6
1960	15,738.8	22,981.7
1961	14,873.3	21,468.4
1962	15,571.6	22,071.7
1963	16,418.0	22,933.4
1964	18,840.1	25,914.9
1965	20,841.7	28,043.2
1966	21,193.9	27,610.6
1967	19,620.6	24,829.9
1968	21,161.1	25,628.1
1969	22,299.0	25,713.8
1970	21,501.6	23,535.0
1971	21,971.3	22,882.0
1972	23,946.7	23,946.7
1973	30,365.5	28,700.9
1974	41,671.7	35,917.7
1975	35,659.8	28,038.8
1976	39,684.1	29,643.8
1977	41,897.8	29,645.4
1978	49,055.4	32,879.0
1979	55,695.8	34,358.9
1980	50,303.9	28,244.8
1981	57,472.9	29,473.3
1982	36,931.9	17,884.7

TABLE C-5. VALUE ADDED, SIC 3312[2] [19] [20] [21] [22]

Year	Value added by manufacture		Employees, 10^3	Value added per employee--1972 dollars, 10^3
	Current dollars 10^6	1972 dollars, 10^6		
1960	6,844.4	9,965.6	550.0	18.1
1961	6,546.3	9,449.0	503.4	18.8
1962	6,620.9	9,384.7	502.2	18.7
1963	7,506.4	10,485.3	500.5	20.9
1964	8,479.6	11,663.8	532.9	21.9
1965	9,379.8	12,620.8	565.4	22.3
1966	9,643.6	12,563.3	559.4	22.5
1967	8,910.1	11,275.8	533.1	21.2
1968	9,275.8	11,233.9	533.1	21.1
1969	9,853.2	11,362.1	537.7	21.1
1970	9,350.5	10.234.8	526.5	19.4
1971	9,563.1	9,959.5	482.2	20.7
1972	10,304.7	10,304.7	469.1	22.0
1973	12,769.4	12,069.4	502.1	24.0
1974	17,425.8	15,019.7	518.0	29.0
1975	13,356.2	10,501.8	451.3	23.3
1976	14,755.5	11,022.3	451.9	24.4
1977	15,021.4	10,628.6	441.4	24.1
1978	19,085.7	12,792.0	443.5	28.8
1979	21,039.0	12,979.0	451.2	28.8
1980	18,632.2	10,461.6	402.9	26.0
1981	20,100.2	10,307.8	390.3	26.4

foundry coke is used as a fuel in the cupolas of foundries. Coke also is used for other miscellaneous processes such as residential and commercial heating. In 1983, only 3 percent of all coke used in the United States was used for these miscellaneous purposes, 92 percent was used in blast furnaces, and the remaining 5 percent was used in foundries.[25] Time-series data for the percent of total U.S. consumption attributable to each use from 1950 to 1980 are shown in Figure C-1.

C.1.2.2 Production Technology. Coke is typically produced from coal in a regenerative type of oven called the by-product oven. The type of coal used in coke production and the length of time the coal is heated (coking time) determine the end use of the coke. Both furnace and foundry coke usually are obtained from the carbonization of a mixture of high- and low-volatile coals. Generally, furnace coke is obtained from a coal mix of 10 to 30 percent low-volatile coal and is coked an average of 18 hours, and foundry coke is obtained from a mix of 50 percent or more low-volatile coal and is coked an average of 30 hours.

The first by-product oven in the United States was built in 1892 to produce coke and to obtain ammonia to be used in the production of soda ash. In such ovens, the by-products of carbonization (such as ammonia, tar, and gas) are collected instead of being emitted into the atmosphere as they were in the older, beehive ovens.

The total amount of coke that can be produced each year is restricted by the number of ovens in operation for that year, and not all ovens are in operation all of the time. Oven operators try to avoid closing down a group of ovens for any reason because of the time and energy lost while the ovens cool and reheat and because of the oven deterioration that results from cooling and reheating. However, it is estimated that, at any time, approximately 5 to 10 percent of existing coke-oven capacity is out of service for rebuilding or repair.[28] In a report written for the Department of Commerce, Father William T. Hogan estimated the potential annual maximum capacity of U.S. oven coke plants as of July 31, 1979.[29] Hogan assumed that almost 10 percent of his estimate of total capacity would be out of service at any given time; therefore, he subtracted the out-of-service capacity from total capacity to obtain maximum annual capacity. The actual

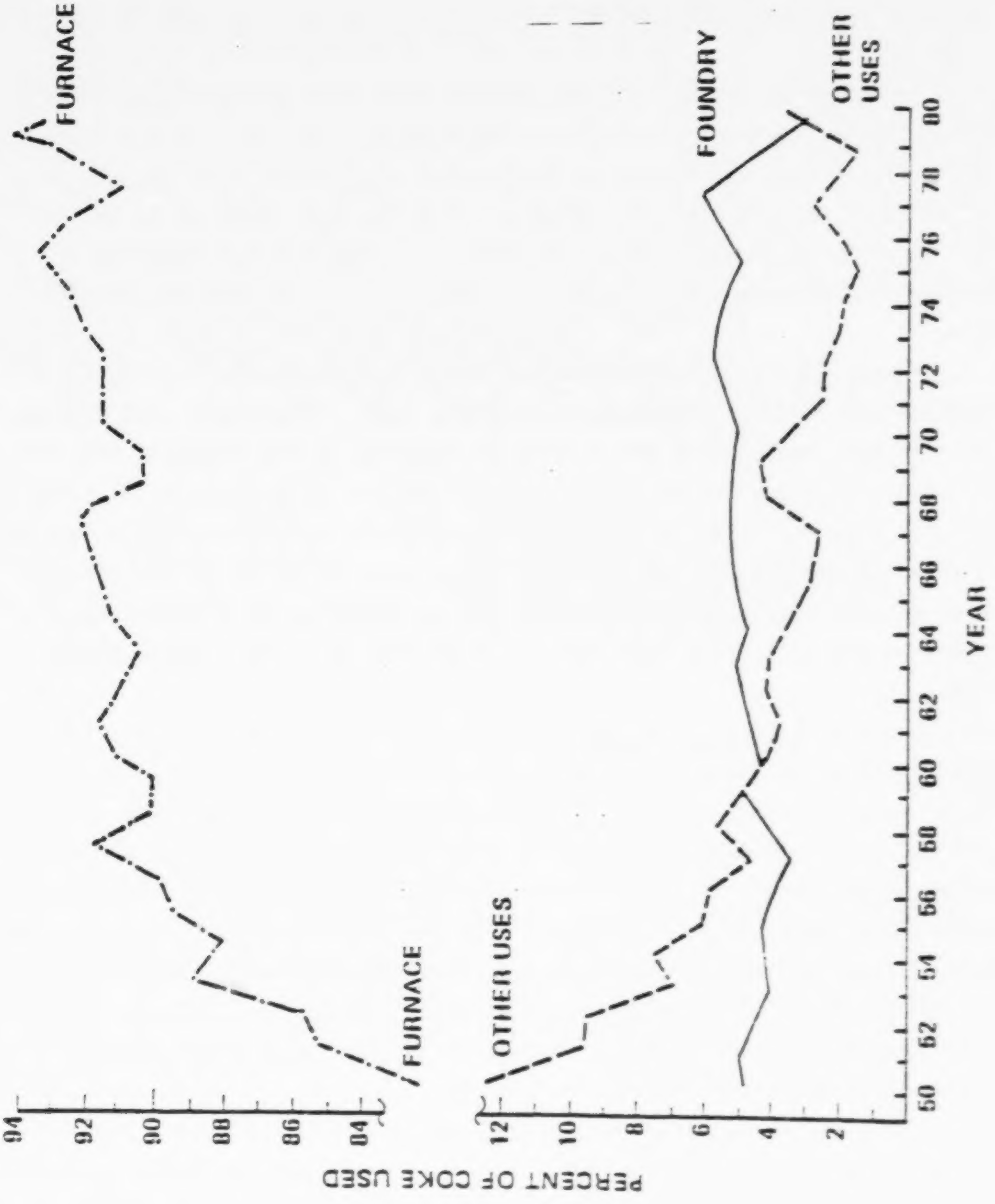

Figure C-1. Uses of oven coke as percents of total coke consumption.[6,26,27]

number of ovens that are out of service in a given year varies greatly. In December 1983, 112 of 6,978 ovens, or 1.6 percent, were being rebuilt or repaired, and annual capacity totalled 35,575,000 Mg.[30] In November 1984, 1,756 of 8,204 ovens, or 21.4 percent, were out of service, and annual capacity totalled 51,180,000 Mg.[5] Table C-6 presents the data for November 1984.

In actuality, ovens that are removed from service and placed on "hot idle" status are those likely to be returned to production in the short term. Ovens that are placed on "cold idle" status are less likely to be returned to service and, historically, have not been returned to service. The capacity of these ovens is included in a plant's total capacity for bookkeeping purposes even though the ovens may be scheduled for demolition.[31]

Within the limits of the number of ovens available for coking, both furnace and foundry coke production levels vary. Some ovens that produce furnace coke can be switched to produce foundry coke by changing the coal mix and increasing the coking time. Furthermore, some ovens that produce foundry coke could be changed to produce furnace coke by changing the coal mix and decreasing the coking time. Also, some variation in the combination of flue temperature and coking time is possible for either type of coke. A shorter coking time results in greater potential annual production.

C.1.2.3 Factors of Production. Table C-7 provides a typical labor and materials cost breakdown for furnace coke production. Coal is the major material input in the production of coke. In 1979, greater than 61 percent of the coal received by coke plants was from mines that were company owned or affiliated.[33] In this same year, 14 States shipped some coal to coke plants outside their borders.[34] Of the coal received by domestic coke plants, over 81 percent came from West Virginia, Kentucky, Pennsylvania, and Virginia.[34] Any potential adverse impact on the coke industry probably will have some impact in these States. A total of 33.6 million Mg of bituminous coal was carbonized in 1983.[35]

Table C-8 shows employment in the by-product coke industry from 1950 to 1970 and the percentage of total SIC 3312 employees in the by-product coke industry. This table shows decreasing employment in the by-product

TABLE C-6. MAXIMUM ANNUAL CAPACITY OF OVEN COKE PLANTS IN THE UNITED STATES IN NOVEMBER 1984[5]

	Number of batteries	Number of ovens	Capacity, Mg
In existence			
Furnace plants	105	6,638	44,810,000
Foundry plants	35	1,566	6,370,000
Total	140	8,204	51,180,000
Out of service[a]			
Furnace plants	(25)	(1,646)	(9,828,000)
Foundry plants	(2)	(110)	(402,000)
Total	(27)	(1,756)	(10,230,000)
In operation[b]			
Furnace plants	80	4,992	34,982,000
Foundry plants	33	1,456	5,968,000
Total	113	6,448	40,950,000

[a] Batteries and ovens down for rebuilding and repair, or on cold idle prior to permanent closure.

[b] Defined as "online" or "on hot idle."

TABLE C-7. TYPICAL COST BREAKDOWNS: FURNACE COKE PRODUCTION AND HOT METAL (BLAST FURNACE) PRODUCTION[32]

Furnace coke production	Percent of cost
Labor and materials	
Coking coal	77.1
Coal transportation	9.4
Labor (operation and maintenance)	6.6
Maintenance materials	6.9
Total labor and material costs	100.0
Hot metal production	
Charge metallics	42.5
Iron ore	(6.3)
Agglomerates	(33.3)
Scrap	(2.9)
Fuel inputs	44.8
Coke	(41.8)
Fuel oil	(3.0)
Limestone fluxes	0.7
Direct labor	7.6
Maintenance	1.5
General expenses	2.9
Total labor and material costs	100.0

TABLE C-8. EMPLOYMENT IN THE BY-PRODUCT COKE INDUSTRY[36]

Year	Number of employees	Percentage of all employees in SIC 3312
1950	20,942	NA
1951	22,058	NA
1952	21,919	NA
1953	21,011	NA
1954	17,944	NA
1955	19,595	NA
1956	19,318	NA
1957	19,203	NA
1958	15,654	3.06
1959	15,865	3.13
1960	15,779	2.87
1961	13,106	2.60
1962	12,723	2.53
1963	12,696	2.54
1964	13,021	2.44
1965	14,003	2.48
1966	13,745	2.46
1967	13,662	2.56
1968	14,136	2.65
1969	13,617	2.53
1970	13,997	2.66
1971[a]	11,955	2.48
1972	11,127	2.37
1973	11,121	2.21
1974	11,207	2.16
1975	12,109	2.68
1976	11,047	2.44
1977	10,196	2.31
1978	10,578	2.38
1979	10,477	2.32
1980	9,673	2.40
1981	8,846	2.27
1982	6,778	2.28

NA = Not applicable.

[a] Figures for 1971-1982 are estimates. See text for more detail.

coke industry. A similar decline in employment has occurred in SIC 3312. Unfortunately, employment data for the by-product coke industry are not available after 1970; however, these figures can be estimated by regressing employment in the by-product coke industry on total iron and steel industry employment and on the ratio of coke used in steel production.* These estimates are also shown in Table C-8.

C.1.3 Demand and Supply Conditions

Domestic consumption of coke from 1950 to 1980 is graphed in Figure C-2. In the early 1950's, the amount of coke consumption was fairly large; an average of 65 million Mg was consumed annually between 1950 and 1958. The late 1950's and early 1960's showed a sharp decrease in coke consumption, with an average of only 48 million Mg consumed annually. Domestic consumption of coke increased during the mid-1960's to mid-1970's to an annual figure of 57 million Mg, but it did not reach the 1950 to 1957 level. The late 1970's showed another slump in coke consumption.

The variation in coke consumption shown in Figure C-2 has both cyclic and trend components. The demand for coke is derived from demands for iron and steel products, and these demands are sensitive to the performance of the overall economy. Cycles in coke demand are linked to cycles in aggregate demand or cycles in demand for particular products such as automobiles.

The trend component in coke consumption results from changes in blast furnace production techniques. Coke is used as a fuel in blast furnaces, but it is not the only fuel that can be used. Coke-oven gas, fuel oil, tar and pitch, natural gas, and blast furnace gas have all been used as supplements to coke in heating the blast furnaces. The increased use of these supplemental fuels over the past 20 years has caused the amount of coke used per ton of pig iron produced (the coke rate) to decrease. Other causes of the decline in coke rate are increased use of oxygen in the blast furnaces and use of higher metallic content ores. Table C-9 shows U.S. pig iron production, coke consumed in the production of pig iron, and the coke rate for 1950 to 1983. (Data limitations make it difficult to calculate the foundry coke rate in cupola production.)

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*Regressions performed by Research Triangle Institute (RTI) in 1980 and 1985.

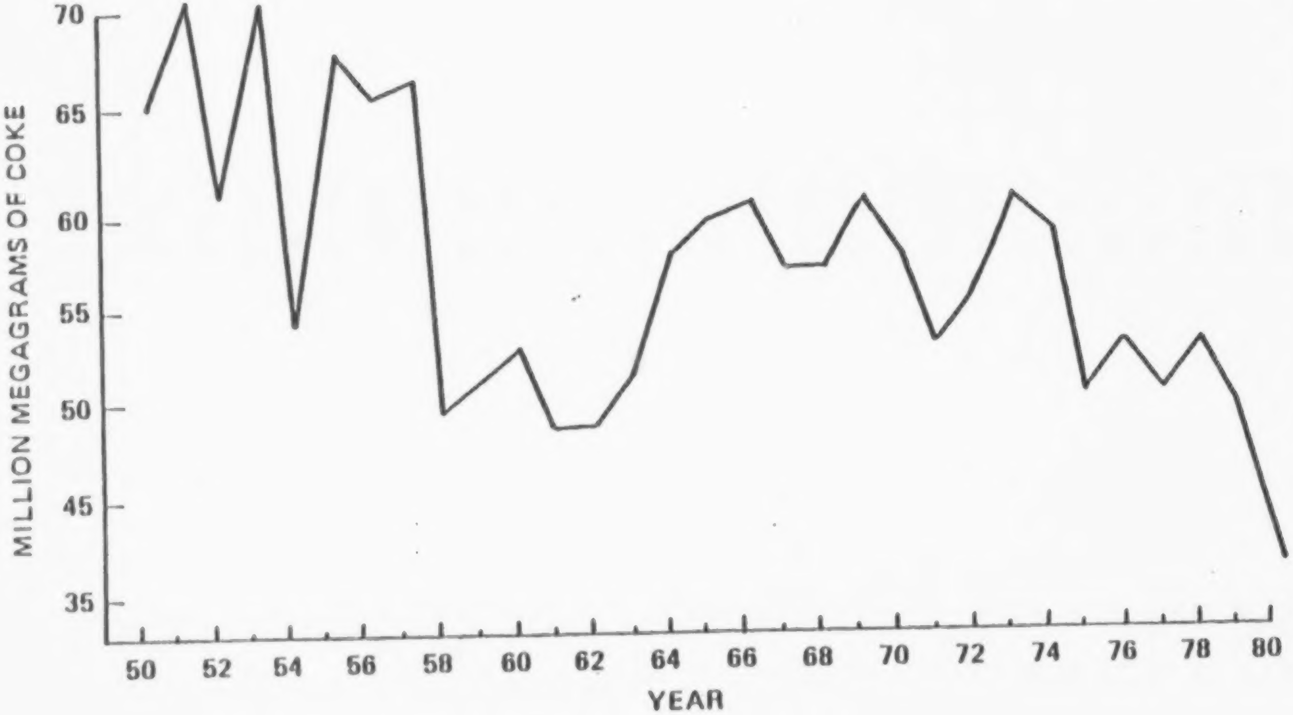

Figure C-2. U.S. apparent consumption of coke.[6,26]

TABLE C-9. COKE RATE[3] [18] [25] [37] [38]

Year	Pig iron production, 10^3 Mg	Coke used in blast furnaces, 10^3 Mg	Coke rate
1950	58,514	51,403	0.86
1951	63,756	55,362	0.87
1952	55,618	49,386	0.89
1953	67,906	58,880	0.87
1954	52,570	46,861	0.89
1955	69,717	60,675	0.87
1956	68,067	58,279	0.86
1957	71,128	60,861	0.86
1958	51,851	42,898	0.83
1959	54,622	44,107	0.81
1960	60,329	46,462	0.77
1961	58,834	42,855	0.73
1962	59,546	42,298	0.71
1963	65,173	44,596	0.68
1964	77,527	51,076	0.66
1965	80,021	53,576	0.67
1966	82,815	54,653	0.66
1967	78,744	51,300	0.65
1968	80,529	51,399	0.64
1969	86,186	55,065	0.64
1970	82,820	54,754	0.66
1971	73,829	48,269	0.65
1972	80,628	50,214	0.62
1973	91,915	54,791	0.60
1974	86,616	51,154	0.59
1975	72,322	44,375	0.61
1976	79,788	47,678	0.60
1977	73,931	44,292	0.60
1978	79,552	47,889	0.60

(continued)

TABLE C-9 (continued)

Year	Pig iron production, 10^3 Mg	Coke used in blast furnaces, 10^3 Mg	Coke rate
1979	78,926	45,862	0.58
1980	62,325	37,583	0.60
1981	66,951	37,832	0.56
1982	39,282	21,918	0.56
1983	46,267	25,009	0.54

Recently, there has been some concern about the ability of the United States' coke-making capacity to support domestic steel production--the major source of coke demand. The study conducted by Hogan and Koelble of the Industrial Economics Research Institute at Fordham University indicates that, in 1978, U.S. production of coke was 14.1 percent below domestic consumption.[39] Imports increased dramatically in that same year. Hogan and Koelble attributed this decline in coke production to the abandonment of coke ovens for environmental reasons and predicted a severe coke shortage by 1982.[40] This prediction was disputed in a Merrill Lynch Institutional Report by Charles Bradford.[41] The Bradford report attributed the lack of adequate U.S. coke production in 1978 to two factors: (1) a coal miner's strike, which caused the drawing down of stocks of coke when they should have been increasing, and (2) the premature closing because of U.S. Environmental Protection Agency (EPA) regulation of some coke ovens that normally would have been replaced before they were closed.[41] The Bradford report stated that a survey of U.S. steel producers revealed that all of the major steel producers were or soon would be self-sufficient with regard to coke-making capacity.[42] The Bradford explanation of 1978 coke imports seems more reasonable because 1979 coke imports decreased about 1.6 million Mg compared to the 1978 level.

The following values describe the situation in the 1980s with respect to production, imports, and apparent consumption of coke (thousand megagrams).[16]

Year	Production	Imports	Consumption	Distributor Stock
1980	41,851	598	37,447	7,009
1981	38,815	478	39,975	5,556
1982	25,506	109	23,384	7,141
1983	23,413	32	27,080	4,024
1984[a]	14,446	248	14,886	2,776

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[a] Two quarters of 1984

Production is less than apparent consumption in 1981, 1983, and 1984. For each of these years, stocks and imports more than accommodate the shortfall. Coke producers were operating at 80 percent of total capacity in November 1984.[5] Thus, it is unlikely that major shortages will develop in the near future.

C.1.4 Market Structure

Market power, the degree to which an individual producer or groups of producers can control market price, is of particular economic importance. Market structure is an important determinant of market power. Pricing behavior is relevant to the choice of the methodology used in assessing the potential impacts of new regulations. It is important to determine if the competitive pricing model (price equal to marginal cost) adequately describes pricing behavior for coke producers.

Any analysis of market structure must consider the characteristics of the industry. This analysis addresses the number of firms producing coke; the concentration of production in specific firms; the degree of integration in coke production; the availability of substitutes for coke; and the availability of substitutes for the commodities for which coke is an input to production. Also, some information on past pricing in the coke industry is presented. These topics will be considered together with financial performance (Section C.1.5) and trends (Section C.1.6) in assessing market behavior (Section C.1.7).

C.1.4.1 Concentration Characteristics and Number of Firms. This section describes various concentration measures that can be computed for the furnace and foundry coke industries. Normally, concentration ratios are used as an indication of the existence of market power. Although concentration ratios are a useful tool for describing industry structure, concentration should not be used as an exclusive measure of market power. Many other factors (e.g., availability of substitutes, product homogeneity, ease of market entry) determine a firm's ability to control market price.

As of November 1984, 23 companies operated by-product coke ovens.[5] [43] Twelve companies are integrated iron and steel producers; 11 companies are merchant firms. These companies owned and operated a total of 51 coke plants; 36 of these plants were captive and 15 of them were merchant. A list of these companies, their plant locations, the major uses of coke at each plant, and plant coke capacities is given in Table C-10. A plant site may include more than one complete plant.

TABLE C-10. COKE PLANTS IN THE UNITED STATES, November 1984[5,44]

Company name	Plant location	Classification of plant	Major uses of coke[a]	Coke capacity, 10³ Mg/yr
Armco, Inc.	Ashland, KY	Captive	Blast furnace	963
	Middletown, OH (2)[b]	Captive	Blast furnace	1,776
Bethlehem Steel Corp.	Bethlehem, PA	Captive	Blast furnace	2,253
	Burns Harbor, IN	Captive	Blast furnace	1,790
	Lackawanna, NY	Merchant	Blast furnace	1,292
	Sparrows Point, MD	Captive	Blast furnace	3,506
Rouge Steel	Dearborn, MI	Captive	Blast furnace	778
Inland Steel Co.	E. Chicago, IN (3)	Captive	Blast furnace	3,715
Interlake, Inc.	Chicago, IL	Captive	Blast furnace	582
The LTV Steel Corp.	Aliquippa, PA[c]	Captive	Blast furnace	1,218
	Cleveland, OH (2)	Captive	Blast furnace	1,760
	E. Chicago, IN	Captive	Blast furnace	948
	Gadsden, AL	Captive	Blast furnace	758
	Pittsburgh, PA	Captive	Blast furnace	1,792
	S. Chicago, IL	Captive	Blast furnace	563
	Thomas, AL	Captive	Blast furnace	315
	Warren, OH	Captive	Blast furnace	945
Lone Star Steel Co.[d]	Lone Star, TX	Captive	Blast furnace	507
National Steel Corp.[e]	Granite City, IL	Captive	Blast furnace	868
	Detroit, MI	Captive	Blast furnace	1,397
Weirton Steel Corp.	Brown's Island, WV	Captive	Blast furnace	1,097
New Boston Coke Corp.[f]	Portsmouth, OH	Captive	Blast furnace	364

(continued)

Footnotes at end of table.

TABLE C-10 (continued)

Company name	Plant location	Classification of plant	Major uses of coke[a]	Coke capacity 10^3 Mg/yr
U.S. Steel Corp.	Clairton, PA (4)	Captive	Blast furnace	5,294
	Fairfield, AL	Captive	Blast furnace	1,822
	Fairless Hills, PA	Captive	Blast furnace	916
	Gary, IN	Captive	Blast furnace	4,228
	Lorain, OH	Captive	Blast furnace	1,496
	Provo, UT	Captive	Blast furnace	1,160
Wheeling-Pittsburgh[g] Steel Corp.	E. Steubenville, WV	Captive	Blast furnace	1,509
	Monessen, PA	Captive	Blast furnace	490
Jim Walter Corp.	Birmingham, AL	Merchant	Blast furnace, foundry	499
Koppers Co., Inc.	Erie, PA	Merchant	Foundry, other industrial	207
	Toledo, OH	Merchant	Foundry	157
	Woodward, AL	Merchant	Blast furnace, foundry	563
Shenango, Inc.	Neville Island, PA	Merchant	Blast furnace, foundry	521
Alabama By-Products Corp.	Tarrant, AL	Merchant	Foundry, other industrial[h]	583
	Keystone, PA	Merchant	Foundry	402
Carondelet Coke Corp.	St. Louis, MO	Merchant	Foundry, other industrial	330
Chattanooga Coke and Chemical Co., Inc.[i]	Chattanooga, TN	Merchant	Foundry, other industrial	130
Citizens Gas and Coke Utility	Indianapolis, IN	Merchant	Foundry	477

(continued)

Footnotes at end of table.

TABLE C-10 (continued)

Company name	Plant location	Classification of plant	Major uses of coke[a]	Coke capacity 10^3 Mg/yr
Detroit Coke Corp.	Detroit, MI	Merchant	Foundry	617
Empire Coke Co.	Holt, AL	Merchant	Foundry	161
Indiana Gas and Chemical Corp.	Terre Haute, IN	Merchant	Foundry, other industrial	132
Tonawanda Coke Corp.	Buffalo, NY	Merchant	Foundry	299

[a] An end use is considered a major use if it is at least 20 percent of the plant's total distribution of coke.

[b] Numbers in parentheses indicate the number of plants at that location. If no number is indicated, only one plant exists at that location.

[c] LTV announced its intention in May 1985 to reduce production of steel at the Aliquippa, Pennsylvania, plant. The plant may convert to a cold-idle status eventually.

[d] Northwest Industries, Inc., the parent company of Lone Star Steel, announced in April 1985 its merger with Farley Industries.

[e] A merger between National Intergroup, Inc., the parent company of National Steel Corp., and Bergen Brunswig Corp. fell through in April 1985, 2 weeks before its scheduled date. Some market consultants feel that National Intergroup, Inc., is now a potential target for corporate raiders.

[f] McLouth Steel Corp., the parent company of New Boston Coke Corp., is operating under Chapter 11 filed in 1981.

[g] Wheeling-Pittsburgh Steel Corp. filed for Chapter 11 in April 1985.

[h] Residential and commercial heating included in other industrial category.

[i] Chattanooga Coke and Chemical Co., Inc., is operating under Chapter 11 filed in March 1984.

Reported capacities in Table C-10 are maximum, nominal figures, which do not include any allowance for outage like that determined for the overall industry in Table C-6. All but one of the largest plants are captive, and most of the merchant plants have very small capacities. Furnace coke production is concentrated in captive plants. Virtually all of the coke used in foundries and in other industries was produced by merchant plants. If coke plant sites were ranked according to capacity, the top 5 plant sites and top 10 plant sites would have 37.1 percent and 54.6 percent of total coke capacity, respectively.

By-product coke plants are concentrated in the States bordering on the Ohio River, probably because of the coal in that area. Pennsylvania contains 12 plants, and Ohio and Indiana each have 8 plants.[5]

Table C-11 divides the United States into 11 coke-consuming and coke-producing regions and shows the amount of coke produced in each region and the locations of coke consumption in 1977. Most of the regions produce the bulk of the coke they consume; only three regions produced less than 80 percent of their own consumption, and only one produced more than it needed for its own consumption. Transportation of coke across long distances is avoided whenever possible to reduce breakage of the product into smaller, less valuable pieces and to minimize freight charges.[46]

The concentration of production or capacity in specific firms may have economic importance. Table C-12 presents the percent of total capacity owned by the largest 4 (of 23) firms. The four-firm concentration ratio for the coke industry has increased over the years. In 1959, the four-firm concentration ratio was 53.5 (the top four firms owned 53.5 percent of total capacity)[47]; in 1984 it was 69.9 percent. Consolidation of the industry through mergers, acquisitions, and closures has encouraged this trend.

In the preceding discussion, furnace and foundry coke production are considered jointly. However, each existing coke battery may be considered a furnace or foundry coke producer, based on the battery's primary use. Separate capacity-based concentration ratios for the two types of coke are calculated based on this allocation. The 1984 four-firm concentration ratio for furnace coke is 75.4; the 1984 four-firm ratio for foundry coke is 65.2.[5]

TABLE C-11. INTERREGIONAL COKE SHIPMENTS IN 1977[45]
(10^3 megagrams)

	Consuming region											
Producing region	AL	CA, CO UT	MD, NY	IL	IN	KY, MO, TN, TX	MI	MN, WI	OH	PA	VA, WV	Total
Alabama	2,228	27	10	81	112	465	195	7	114	1	51	3,361
California, Colorado, Utah	0	2,668	0	0	0	0	0	0	0	0	0	2,668
Maryland, New York	0	3	4,392	123	0	22	88	0	6	8	0	4,642
Illinois	0	0	0	1,424	0	0	0	0	0	0	0	1,424
Indiana	0	5	0	69	7,594	35	97	11	62	3	0	7,876
Kentucky, Missouri, Tennessee, Texas	14	18	0	15	5	928	125	0	13	0	20	1,138
Michigan	0	0	0	0	7	1	2,639	0	6	0	0	2,653
Minnestoa, Wisconsin	0	6	0	269	70	1	61	158	5	1	0	571
Ohio	0	4	0	138	366	379	260	0	6,356	2	12	7,517
Pennsylvania	9	0	51	1,241	134	3	52	0	1,370	10,257	3	13,120
Virgina, West Virginia	0	0	0	0	0	8	412	0	0	214	2,465	3,099
TOTAL	2,251	2,731	4,453	3,360	8,288	1,842	3,929	176	7,932	10,556	2,551	48,069

TABLE C-12. PERCENT OF COKE CAPACITY OWNED BY TOP FIRMS NOVEMBER 1984[5]

Firm	Capacity, 10^3 Mg	Percent of total capacity
U.S. Steel, Inc.	14,916	29.14
Bethlehem Steel Corp.	8,841	17.27
The LTV Steel Corp.	8,299	16.22
Inland Steel Co.	3,715	7.26
Sum of largest four firms	35,771	69.89

Concentration in the steel industry has economic relevance because a large fraction of all furnace coke is produced by integrated iron and steel companies. Historically, the eight largest steel producers have been responsible for approximately 75 percent of industry production. However, from 1950 to 1976, the share of production attributable to the top four firms declined from 62 percent to 53 percent.[48] In 1981, the seven largest steel companies produced about 70 percent of steel made in the United States.[49]

In summary, concentration exists in the production of both types of coke and in steel production. However, the concentration probably is not sufficient to guarantee market power, and many companies are involved in the production of both coke and steel products. Other factors must be considered in any final assessment of market power.

C.1.4.2 Integration Characteristics. When one firm carries out activities that are at separate stages of the same productive process, especially activities that might otherwise be performed by separate firms, that firm is said to be vertically integrated. Through vertical integration, the firm substitutes intrafirm transfers for purchases from suppliers and/or sales to distributors. A firm may seek to supply its own materials inputs to ensure a stable supply schedule or to protect itself from monopolistic suppliers. The firm may seek to fabricate further or distribute its own products to maintain greater control over the consuming markets or to lessen the chance of being shut out of the market by large buyers or middlemen. Therefore, the presence of vertical integration may constitute a firm's attempt to control costs or ensure input supplies. Vertical integration does not guarantee market power (control over market price).

Many coke-producing firms, especially furnace coke producers, are vertically integrated enterprises. As previously mentioned, 36 of the existing coke plants are captive, i.e., they are connected with blast furnaces and/or steel mills. In addition, many coke firms own coal mines, and greater than 61.0 percent of the coal used in ovens was from captive mines in 1979.[33] Assurance of coal supply to coke production and coke supply to pig iron production appears to be the motivation behind such integration.

One implication of vertical integration is that much of the furnace coke used in the United States never enters the open market--it is consumed by the producing company. Accordingly, the impact analysis for furnace coke (Section C.2.2) uses an implied price for furnace coke based on its value in producing steel products, which are transferred on the open market.

C.1.4.3 Substitutes. Substitutes for a given commodity reduce the potential for market power in production of the commodity. The substitution of other inputs for coke in blast furnaces is somewhat limited, but not totally unfeasible. In addition, electric arc furnaces, which do not require coke, are becoming increasingly important in steel production. The trend toward electric arc furnaces and minimills has eased entry into the iron and steel industry, which in turn reduces market power.

Imported coke also can be substituted for domestically produced coke. In fact, although U.S. iron and steel producers prefer to rely on domestic sources of coke, coke imports have increased most recently. If the cost of domestic coke increased substantially compared to the cost of imported coke, U.S. iron and steel producers might attempt to increase imports even more. Correspondingly, if costs of imported coke are reduced because of improved foreign technology and productivity, reductions in foreign labor cost, or other reasons, imports might become more desirable.

Furthermore, substitutes exist for the final products (iron and steel) to which coke is an input. Increases in the price of coke and the resulting increases in the price of iron and steel products can lead to some substitution of other materials for iron and steel, which also reduces market power in the production of coke. Analogous substitutions for foundry coke are possible, and cupola production of ferrous products, which uses foundry coke, has competition from electric arc furnaces that do not use coke. Hence, there is a technological substitute for foundry coke in the manufacture of ferrous products. Furthermore, imported foundry coke can be substituted for domestic foundry production. In conclusion, some substitution for coke is possible in the manufacture of both steel and ferrous products.

C.1.4.4 Pricing History. As previously indicated, a significant portion of all U.S. coke production is not traded on the market. However, the U.S. Bureau of Mines and the Energy Information Administration collect annual data on coke production and consumption and give the quantity and the total value of coke consumed by producing industries, sold on the open market, and imported. Dividing total value by quantity yields an average price for each of these categories. Time-series data on these three average values are given in Table C-13. (Furnace and foundry coke are combined in these figures.)

Also shown in Table C-13 are data on the average value of coal that is carbonized in coke ovens. An examination of coke and coal prices reveals that increases in coal prices generally coincide with increases in coke prices. In fact, only 3 years show an increase in the price of coal that was not accompanied by an increase in the price of the two categories of coke. Although it is impossible to conclude from this trend that individual firms have market power, it indicates that the industry can pass through some increases in costs.

C.1.4.5 Market Structure Summary. Although there is no perfect method for measuring the extent of market power, the preceding sections addressed four characteristics used to measure the potential for market power--concentration, integration, substitution, and historical price trends. Concentration statistics indicated that some potential for market power exists in the coke industry, yet these statistics are not conclusive proof. Similarly, vertical integration in the steel industry is not conclusive in identifying the presence of market power because vertical integration is a method of controlling the cost and ensuring the quality and supply of inputs. Finally, the possibility of substitution represents a strong argument against the existence of extensive market power in the coke-making industry.

C.1.5 Financial Performance

Financial data on the coke-producing firms or their parent firms, including captive and merchant furnace and foundry producers, are shown in Table C-14. Firms for which data are not available are noted.

Ten companies show negative earnings before interest and taxes. Of these, nine are furnace coke producers, whose earnings reflect the disastrous years for the steel industry. As mentioned, in 1983, steel firms had

TABLE C-13. COMPARISON OF COAL PRICES AND DOMESTIC AND IMPORTED COKE PRICES[6, 50, 51, 52, 53]

	Average value of coal carbonized in coke ovens,[a,b] $/Mg	Average value of oven coke used by producers,[a] $/Mg	Average value of oven coke sold commercially,[a] $/Mg	Average value of imported coke,[a,c] $/Mg
1950	9.56	14.26	14.54	13.34
1951	9.85	14.50	15.72	13.17
1952	10.17	15.11	17.63	15.96
1953	10.19	15.36	17.96	12.02
1954	9.92	17.33	18.95	11.98
1955	9.74	17.90	18.52	12.26
1956	10.31	19.39	20.27	12.38
1957	10.92	19.98	21.51	14.43
1958	10.90	19.82	21.90	14.25
1959	10.89	19.16	23.03	12.89
1960	10.90	19.92	22.32	13.06
1961	10.79	19.12	23.30	13.44
1962	10.86	19.53	23.36	14.42
1963	10.46	18.88	23.24	14.78
1964	10.23	19.17	22.85	16.10
1965	10.48	17.89	23.90	16.95
1966	10.78	18.40	24.49	20.60
1967	11.05	18.58	24.99	20.41
1968	11.03	19.57	24.25	22.31
1969	11.49	21.54	27.01	21.36
1970	13.46	30.30	33.04	25.46
1971	15.43	32.86	41.29	31.93
1972	17.34	35.76	44.87	27.70
1973	20.19	41.34	47.31	40.16
1974	40.22	82.32	72.47	60.14
1975	48.73	92.84	96.61	94.84
1976	48.68	93.83	104.01	93.35
1977	50.99	90.57	111.95	--
1978	57.37	105.79	118.03	--
1979	55.88	117.39	107.54	94.32
1980	62.09	123.42	113.24	87.12
1981	69.29	125.52	124.34	89.59
1982	71.62	131.24	126.24	84.61
1983	65.36	124.57	124.67	61.45

[a] Both furnace and foundry coke and the coals used to produce furnace and foundry coke are included in these figures.

[b] Market value at the oven (current dollars).

[c] General customs value as reported by the U.S. Department of Commerce (current dollars).

TABLE C-14. FINANCIAL INFORMATION ON COKE-PRODUCING FIRMS, 1983
(million 1983 dollars)[a] [54] [55] [56] [57]

Company name[b]	Net sales	EBIT[c]	Cash flow[d]
Armco, Inc.	4,165	(526)	70
Bethlehem Steel Corp.	4,898	(239)	129[g]
Ford Motor Co. (Rouge Steel)	44,455	2,166	5,542
Inland Steel Co.	3,046	(177)	106[g]
Interlake, Inc.	835	38	67
The LTV Steel Corp.	4,578	(252)	(164)[g]
McLouth Steel Corp.[i,j] (New Boston Coke Corp.)	11	(0.09)	k
National Intergroup, Inc.[l] (National Steel Corp.)	2,993	(177)	161
Northwest Industries[m] (Lone Star Steel Co.)	1,608	(104)	154[g]
Shenango Furnace Co., Inc.[n,o] (Shenango, Inc.)	145	k	k
U.S. Steel Corp.	15,869	(1,208)	1,563[g]
Weirton Steel Corp.[p]	1,000	k	k
Wheeling-Pittsburgh Steel Corp.[q]	772	(72)	(70)[g]
Jim Walter Corp.[n]	2,025	113	159
Koppers Co., Inc.[n]	1,566	42	174[g]
Alabama Byproducts Corp.	229	k	192
Carondelet Coke Corp.[r]	k	k	k
Chattanooga Coke and Chemicals Co., Inc.[s]	17	k	k
Citizens Gas and Coke Utility	316	k	91
Detroit Coke Corp.[r,t]	k	k	k
Indiana Gas and Chemical Corp.	64	(0.2)	k
McWane, Inc. (Empir[illegible]oke Co.)	k	k	k
Tonawanda Coke Corp.[r]	k	k	k

Footnotes at end of table.

TABLE C-14 (continued)

Company name[b]	Annual interest expense	Total assets	Long-term debt	Tangible net worth[f]
Armco, Inc.	154	3,609	832	1,213
Bethlehem Steel Corp.	104	4,457	1,134	1,088
Ford Motor Co.	567	23,869	2,713	7,545
Inland Steel Co.	68	2,626	788	1,118
Interlake, Inc.	12	674	116	314
The LTV Steel Corp.	171	4,406	1,560	985
McLouth Steel Corp.[i,j] (New Boston Coke Corp.)	k	11	3	(4)
National Intergroup, Inc. (National Steel Corp.)	62	2,649	606	875
Northwest Industries (Lone Star Steel Co.)	63	1,811	451	530
Shenango Furnace Co., Inc.[n,o] (Shenango, Inc.)	k	k	10	73
U.S. Steel Corp.	1,074	19,314	7,164	4,570
Weirton Steel Corp.[p]	k	357	149	k
Wheeling-Pittsburgh Steel Corp.[q]	58	1,241	514	247
Jim Walter Corp.[n]	140	2,609	1,151	717
Koppers Co., Inc.[n]	26	1,175	233	554
Alabama Byproducts Corp.	6	243	52	243
Carondelet Coke Corp.[r]	k	k	k	k
Chattanooga Coke and Chemicals Co., Inc.[s]	k	k	k	k
Citizens Gas and Coke Utility	6	343	145	136
Detroit Coke Corp.[r,t]	k	28	19	(3)
Indiana Gas and Chemical Corp.	k	36	0	22
McWane, Inc. (Empire Coke Co.)	0.5	112	21	74
Tonawanda Coke Corp.[r]	k	k	k	k

Footnotes at end of table. (continued)

TABLE C-14 (continued)

Company name[b]	Net working capital[a]	Current assets	Current liabilities
Armco, Inc.	563	1,576	1,013
Bethlehem Steel Corp.	271	1,259	988
Ford Motor Co. (Rouge Steel)	503	10,819	10,316
Inland Steel Co.	233	789	556
Interlake, Inc.	203	378	175
The LTV Steel Corp.	538	1,848	1,310
McLouth Steel Corp.[i,j] (New Boston Coke Corp.)	(10)	2	12
National Intergroup, Inc. (National Steel Corp.)	252	875	623
Northwest Industries (Lone Star Steel Co.)	338	762	424
Shenango Furnace Co., Inc.[n,o] (Shenango, Inc.)	16	43	27
U.S. Steel Corp.	789	4,298	3,509
Weirton Steel Corp.[p]	147	332	185
Wheeling-Pittsburgh Steel Corp.[q]	102	343	241
Jim Walter Corp.[n]	136	1,594	1,458
Koppers Co., Inc.[n]	282	527	245
Alabama Byproducts Corp.	50	73	23
Carondelet Coke Corp.[r]	[k]	[k]	[k]
Chattanooga Coke and Chemicals Co., Inc.[s]	[k]	[k]	[k]
Citizens Gas and Coke Utility	20	82	62
Detroit Coke Corp.[r,t]	1	13	12
Indiana Gas and Chemical Corp.	2	13	11
McWane, Inc. (Empire Coke Co.)	48	58	10
Tonawanda Coke Corp.[r]	[k]	[k]	[k]

Footnotes at end of table. (continued)

TABLE C-14 (continued)

[a] Values in parentheses represent negative numbers.

[b] Parent firms of furnace coke producers are listed first, followed by parent firms of foundry coke producers. Subsidiaries are listed in parentheses below parent companies.

[c] EBIT = earnings before interest and taxes.

[d] Cash flow = operating income + depreciation - interest expenses - taxes.

[e] Net working capital = current assets - current liabilities.

[f] Tangible net worth = equity - intangible assets.

[g] Received income tax credit in 1983. Income tax represented as zero in cash flow calculation.

[i] McLouth Steel Corp. has debtor-in-possession status. The parent company filed for bankruptcy in 1981 and filed a petition for reorganization in December 1984. Financial information listed is for the subsidiary.

[j] Figures are interim values reported for first 11 months of 1984. Converted to 1983 dollars using GNP implicit price deflator.

[k] Information not available..

[l] A merger between National Intergroup, Inc., the parent company of National Steel Corp., and Bergen Brunswig Corp. fell through in April 1985, 2 weeks before its scheduled date. Some market consultants feel that National Intergroup, Inc., is now a potential target for corporate raiders.

[m] Northwest Industries, Inc., the parent company of Lone Star Steel, announced in April 1985 its merger with Farley Industries.

[n] Producer of both furnace and foundry coke.

[o] Financial information listed applies to subsidiary rather than parent company.

[p] Employees formally took control in January 1984. All figures are interim values reported for first 3 months of 1984. Conversion to 1983 dollars using GNP implicit price deflator.

[q] Wheeling-Pittsburgh Steel Corp. filed for Chapter 11 in April 1985.

[r] Owned by James D. Crane. Financial information denied.

[s] Chattanooga Coke and Chemicals Co., Inc. has debtor-in-possession status. The company filed for arrangement under Chapter 11 in March 1984.

[t] Latest information available is for 1982. Conversion to 1983 dollars using GNP implicit price deflator.

financial losses totalling $3.6 billion. The balance of steel trade favored imports by a 14 to 1 import-export ratio. Imports totalled 20.5 percent of apparent supply in 1983.[58]

Two integrated steel producers exhibit negative cash flows, while a third has negative calculated working capital, as financial resources have dwindled with the recession. Two companies, one furnace coke producer and one foundry coke producer, are operating under bankruptcy status.

From the financial data in Table C-14, three ratios have been calculated (Table C-15). The first, a liquidity ratio, is a measure of a firm's ability to meet its current obligations as they are due. A liquidity ratio above 1.0 indicates that the firm is able to pay its current debts with its current assets; the higher the ratio, the bigger the difference between current obligations and the firm's ability to meet them. All of the coke-producing firms have liquidity ratios between 1.0 and 4.0, with the exceptions of McLouth Steel (0.17) and McWane, Inc. (5.80). These figures are consistent with liquidity ratios for firms in a wide variety of manufacturing industries.

The second ratio, a coverage ratio, gives an indication of the firm's ability to meet its interest payments. A high ratio indicates that the firm is more likely to be able to meet interest payments on its loans. This ratio also can be used to determine the ability of a firm to obtain more loans. The coverage ratio of the coke-producing firms ranged from 0.8 to 3.9. Seven firms for which information was available had negative coverage ratios because of negative EBIT values. The positive ratios are comparable to the coverage evidenced in most manufacturing industries. The poor performance of those firms with negative ratios may be a result of problems in the steel industry. However, many firms continue to make investments funded through mergers, joint ventures, and other means.

The last of the ratios, a leverage ratio, indicates the relationship between the capital contributed by creditors and that contributed by the owners. Leverage magnifies returns to owners. Aggressive use of debt increases the chance of default and bankruptcy. The chance of larger returns must be balanced with the increased risk of such actions. The leverage ratio indicates the vulnerability of the firm to downward business

TABLE C-15. FINANCIAL RATIOS FOR COKE-PRODUCING FIRMS

Company name[a]	Liquidity ratio[b]	Coverage ratio[c]	Leverage ratio[d]
Armco, Inc.	1.56	-3.42[e]	1.52
Bethlehem Steel Corp.	1.27	-2.30[e]	1.95
Ford Motor Co. (Rouge Steel)	1.05	3.82	1.73
Inland Steel Co.	1.42	-0.25[e]	1.20
Interlake, Inc.	2.16	3.08	0.93
The LTV Corp.	1.41	-1.47[e]	2.91
McLouth Steel Corp. (New Boston Coke Corp.)	0.17	f	-3.75[e]
National Intergroup, Inc. (National Steel Corp.)	1.40	-2.85[e]	1.40
Northwest Industries (Lone Star Steel Co.)	1.80	-1.66[e]	1.65
Shenango Furnace Co., Inc. (Shenango, Inc.)[g]	1.59	f	0.51
U.S. Steel Corp.	1.22	1.12	2.34
Weirton Steel Corp.	1.79	f	f
Wheeling-Pittsburgh Steel Corp.	1.42	-1.25[e]	3.06
Jim Walter Corp.[g]	1.09	0.81	3.64
Koppers Co., Inc.[g]	2.15	1.59	0.86
Alabama Byproducts Corp.	3.17	f	0.35
Citizens Gas and Coke Utility	1.32	f	1.52
Detroit Coke Corp.	1.08	f	-10.3[e]
Indiana Gas and Chemical Corp.	1.18	f	0.50

Footnotes at end of table. (continued)

TABLE C-15 (continued)

Company name[a]	Liquidity ratio[b]	Coverage ratio[c]	Leverage ratio[d]
McWane, Inc. (Empire Coke Co.)	5.80	[f]	0.42

[a] Parent firms of furnace coke producers are listed first, followed by parent firms of foundry coke producers. Subsidiaries are listed in parentheses below parent companies. No ratios were calculated for Carondelet Coke Corp., Chattanooga Coke and Chemicals Co., Inc., and Tonawanda Coke Corp. because of a lack of information.

[b] $\text{Liquidity ratio} = \frac{\text{Current assets}}{\text{Current liabilities}}$.

[c] $\text{Coverage ratio} = \frac{\text{EBIT}}{\text{Annual interest expense}}$.

[d] $\text{Leverage ratio} = \frac{\text{Total liabilities}}{\text{Tangible net worth}}$.

[e] Negative values are not meaningful.

[f] Information not available.

[g] Produces both furnace and foundry coke.

cycles. Also, a high ratio reveals a low future debt capacity, i.e. additions to debt in the future are less likely. The firms with coke-making capacity had leverage ratios that ranged from 0.3 to 3.7. Six companies had ratios below 1.0, while one firm experienced a negative ratio. These figures highlight the poor financial condition of many firms in the coke industry. Currently, firms with coke-making capacity are engaged in substantial amounts of debt financing, while continuing to make investments.

Another measure of financial performance is the rate of return on equity. Studies of the iron and steel industry show low rates of return on equity. In an analysis performed by Temple, Barker, and Sloane, Inc. (TBS), the real (net of inflation) rate of return in the steel industry was estimated to be 0.2 percent for the period 1970 to 1980. The TBS analysis projected a rate of return on equity of 1.0 percent for 1980 to 1990.[59] These estimates of historical and projected return on equity compare very poorly with estimates of the required return on investment in the steel industry. A difference between realized and required returns implies that equity financing of capital expenditures may be difficult.

As noted, low rates of return on equity affect common stock prices and have implications for future investment financing, including environmental control expenditures. The following data represent total pollution abatement capital expenditures (PACE) as a percentage of new capital expenditures (NCE) for SIC 3312.[2] [60] [61] [62]

Year	Percentage PACE of NCE
1975	20.25
1976	20.92
1977	22.95
1978	22.20
1979	25.57
1980	20.11
1981	15.75
1982	12.32

PACE as a percentage of NCE peaked at 25.57 percent in 1979, after having been fairly steady throughout the latter part of the 1970's. The trend is the 1980's show a PACE as a declining percentage of NCE. This decrease may reflect the capital availability restrictions experienced by the steel industry during this period.

For the steel industry, issuing new stock to raise investment capital is unlikely under current circumstances. If environmental and other control investments cannot be financed through new equity, another source of funds must be found. Increased debt is one potential source. However, firms with coke-making capacity already have incurred substantial amounts of debt. The TBS analysis concluded that to avoid deterioration in its financial condition, the steel industry is likely to reduce expenditures to modernize productive facilities rather than increase its external financing.[63]

The steel industry has had to resort to more creative forms of financing to provide funds for modernization of facilities. This upgrading is a key to gaining and maintaining a competitive position with respect to imports. Cash flow for the industry has been below capital requirements for the past two decades. Mergers, joint ventures, shared production arrangements, abandonment of uneconomic facilities, and the sales of assets are likely to continue being sources of capital.[64] Funds advanced by customers, with repayment geared to earnings, have been used for equipment modernization.[65]

C.1.6 Industry Trends

The demand for coke is derived from the demand for steel produced by processes that utilize coke. Hence, a description of steel industry trends in technological development and production is a useful indicator of future coke production and coke capacity requirements.

As mentioned, there has been a technological shift, which is expected to continue, toward labor-saving technology. Trends in modernization are away from open-hearth furnace production and toward electric arc furnaces and basic oxygen furnaces. In 1960, these processes accounted for 88.2 percent, 9.5 percent, and 3.3 percent of U.S. production, respectively, while in 1982 these values were 8.2 percent, 31.1 percent, and 60.7 percent.[66] In 1985, basic oxygen furnaces are expected to account for 61.5 percent of steel production, with electric furnaces contributing 34.0 percent or more, and open hearth furnaces declining to 6.1 percent or less.[67] Electric arc and basic oxygen furnaces represent reductions in production time, as well as shifts to less expensive inputs.[67] The increased use of these types of furnaces will result in some decrease in demand for coke.

Other changes have improved industry productivity, quality of yields, and energy efficiency. In-ladle processes (performed after the melting furnace stage) include inert gas stirring and vacuum treatments.[68] These techniques yield higher quality steel.

The use of continuous casters, which convert molten steel directly into shapes ready for rolling, has increased from 18 percent of production in the late 1970's to 35 percent in 1984.[69] Yield of finished product per ton of raw steel may be boosted to 95 percent from the current 76 percent by use of this process. For each ton of finished steel produced using this technology, 15 percent to 20 percent less raw steel is required, while 40 percent to 50 percent less energy is needed.[67] The impact of these technological developments on the coke industry is unknown. Any effects will be through productivity improvements in the steel industry.

Technological trends have reduced steel use per unit of output of durable goods. Since the 1970's, the decline in consumption of steel per dollar of GNP has averaged 4 percent annually, with continued decline expected.[70] Increases in economic growth are predicted to offset this effect, resulting in an increase in steel use to 95 million Mg by 1988, with domestic shipments representing a 5-percent average annual rate increase over the 1983 to 1988 period.[65] Projections by the U.S. Bureau of Mines predict U.S. raw steel demand will be 138 million Mg in 1990, and 164 million Mg in 2000.[71]

Steelmaking capacity utilization recently has been low, averaging 47.3 percent in 1982 and 55.4 percent in 1983.[72] In 1984, this rate rose to 82 percent in April before dropping to 57 percent in September.[73] Capacity utilization is an important measure of industry performance because of high fixed costs for the industry. The larger the volume of production, the smaller the cost per unit of steel produced. For the steel industry, the break-even point for operations is at approximately 65 percent of capability, although this figure is highly dependent on prices.[73] This means that steel companies have been operating at losses for several years.

The steel industry has responded to this financial difficulty by permanently reducing capacity. Since 1983, this reduction has been more than 10 percent, with perhaps another 5-percent cut necessary.[73] From

122.5 million Mg in 1984, capacity is likely to be trimmed to 109 million Mg by the late 1980's.[73] However, the U.S.Bureau of Mines predicts U.S. production of raw steel will rise to 113 million Mg in 1990, and to 132 million Mg in 2000, under assumptions of slow growth in the rate of production and increases in demand.[71] Changes in capacity utilization affect coke production only to the extent that coke is an input to the steel production process. Reductions in steel production, coupled with shifts to noncoke energy inputs could greatly reduce demand for coke.

The emergence of minimills to supply regional demand for steel has had an impact on the operation of the larger integrated steel mills. Mini mills now account for approximately 20 percent of U.S. steel production, at a cost per ton of installed capacity about 75 percent less than for integrated plants. The use of electric arc furnaces in minimills may result in dramatic reductions in coke demand if such mills claim 40 percent of the steel market by 2000, as some predict.[74]

The combination of the factors described in this section indicate that coke consumption is destined to continue declining. Technological improvements are likely to result in an input shift away from coke, while reduced capacity in the integrated steel industry signals a decrease in amounts of coke needed for blast furnace steel production.

C.1.7 Market Behavior: Conclusions

Market structure, financial performance, and potential growth influence the choice of a methodology to describe supply responses in the coke-making industry. Although some characteristics of this industry indicate a potential for market power, other characteristics belie it.

Some concentration exists in coke-making capacity and steel production; however, many firms produce coke and iron and steel products. Vertical integration is substantial; however, integration appears to result primarily from a desire for increased certainty in the supply of critical inputs. Furthermore, substitution through alternative technologies and coke imports is feasible, and some substitutes for the industry's final products (iron and steel) are available. In any industry, the potential for substitution is a major factor leading to competitive pricing. Certainly, the financial profile of coke-making firms is not indicative of monopoly profits. Prospects for industry growth are limited. An individual firm must actively compete with other firms in the industry to improve its profit position, or even to remain viable.

No industry matches the textbook definition of perfect competition. The important issue is whether the competitive model satisfactorily captures major behavioral responses of firms in the industry. Based on the factors outlined in this section, the competitive pricing model adequately describes supply responses for coke-making firms.

C.2. ECONOMIC IMPACT OF REGULATORY ALTERNATIVES

C.2.1 Summary

Economic impacts are projected for the baseline and for each regulatory alternative. Furnace and foundry coke impacts are examined separately because their production costs and markets differ. In the reanalysis, all cost and price impacts are in second-quarter 1984 dollars.

All costs and prices used in calculations were originally in third-quarter 1979 dollars, except prices of steel, furnace coke, and foundry coke, which were in 1983 dollars. Conversions to the 1984 values were made by multiplying the 1979 values by 1.362, the ratio of 1984 second-quarter GNP implicit price deflator to the 1979 GNP implicit price deflator.[14 75] The 1983 values were converted by multiplying by 1.032, the ratio of the producer price index for second-quarter 1984 to the same index for 1983.[76]

When measured on a per-unit of output basis, the costs of meeting baseline regulations for foundry coke plants tend to be greater than those for furnace coke plants for two reasons. First, some economies of scale are present for some of the controls. Foundry plants tend to be smaller than furnace plants; thus, they have higher per-unit control costs. Second, for a given battery, foundry coke output will be less than furnace coke output because foundry coke coking time is about two-thirds longer than furnace coke coking time.

Regulatory Alternative II has annualized costs of $4.8 million above baseline for furnace and foundry coke producers combined. Regulatory Alternative II requires capital expenditures of $45 million above baseline for furnace and foundry coke producers combined. Regulatory Alternative III would result in annualized costs of $15.3 million and capital costs of $80 million over baseline for the combined furnace and foundry coke sectors. The values are the same whether import competition is assumed for foundry coke producers (Scenario B) or not (Scenario A). These costs differ from engineering estimates because of the calculation of costs based on batteries with marginal cost of production below price, rather than all batteries.

Price impacts are estimated under the empirically supported hypothesis that furnace coke demand is responsive to higher coke prices. Foundry coke demand also is assumed to respond to price. Regulatory Alternative II would have impacts of $0.13/Mg (0.12 percent change) on the price of furnace coke, and $0.99/Mg (0.58 percent change) on the price of foundry coke under Scenario A (1984 dollars). Under Scenario B, there are no price effects. Regulatory Alternative III would result in furnace coke price increases of $0.36/Mg (0.33 percent) and $1.46/Mg (0.86 percent) price increase for foundry coke under Scenario A, and $0.00/Mg change under Scenario B.

Regulatory Alternatives II and III would have less than a 1.0-percent impact on the production of either furnace or foundry coke under Scenario A. Under Scenario B, Regulatory Alternative II would decrease foundry coke production by 2.1 percent, while Regulatory Alternative III would result in a 3.2-percent reduction in foundry coke production. There are 14 furnace coke batteries that currently appear uneconomic. There are no uneconomic foundry coke batteries. Regulatory Alternative II does not force any more batteries into the uneconomic production region. Regulatory Alternative III results in one additional furnace coke battery being pushed into the uneconomic region.

C.2.2 Methodology

The following approach focuses on the long-run adjustment process of furnace and foundry coke producers to the higher costs of coke production that the regulatory alternatives will create. These long-run adjustments involve investment and shutdown decisions. Short-run adjustments, such as altering coking times, to meet the fluctuations in the demand for coke are not the subject of this analysis.

Because of differences in production costs and markets, furnace and foundry coke producers are modeled separately. Both are assumed to behave as if they were competitive industries selling coke in a market. This assumption is somewhat more realistic for foundry than for furnace coke producers because most furnace coke is produced in plants captive to the steel industry. However, interfirm and intrafirm shipments of coke are not uncommon, as can be inferred from Table C-11. A plant-by-plant review of the coke industry by Hogan and Koelble also confirmed the existence of such exchanges.[77]

A set of programmed models has been developed to produce intraindustry and interindustry estimates of the economic impacts of the alternative regulations. The models are applied to both furnace and foundry coke, and the sectors included are coke, steel, and ferrous foundries. The rest of the economy is incorporated into the interindustry portion of the analysis.

The analytical approach incorporates a production cost model of the coke industry, based on engineering data, and an econometric model of the steel industry. The interrelationships of these models for furnace coke are shown in Figure C-3. The upper portion of Figure C-3 encompasses the supply side impacts of the regulatory alternatives; the lower portion contains the demand side impacts. In the synthesis step, the two sides are brought together, and the equilibrium price and quantity relationships are determined. An analogous diagram for foundry coke would substitute ferrous foundry products for steel. The methodology is described further in the following subsections.

C.2.2.1 Supply Side. A production cost model that incorporates technical relationships and engineering cost estimates is used with plant-specific information to compute separate industry supply functions, with and without additional controls.[78] Supply functions are estimated on a year-by-year basis for furnace and foundry coke plants projected to be in existence between 1984 and 1995. Both coke production costs and the costs that plants incur to meet existing environmental regulations are computed to estimate the industry supply curve before any additional controls are applied. Estimates of the costs of control for compliance with the regulatory alternatives are used to compute the projected upward shifts in that supply function. All costs are in 1983 dollars, converted to 1984 dollars for this reanalysis.

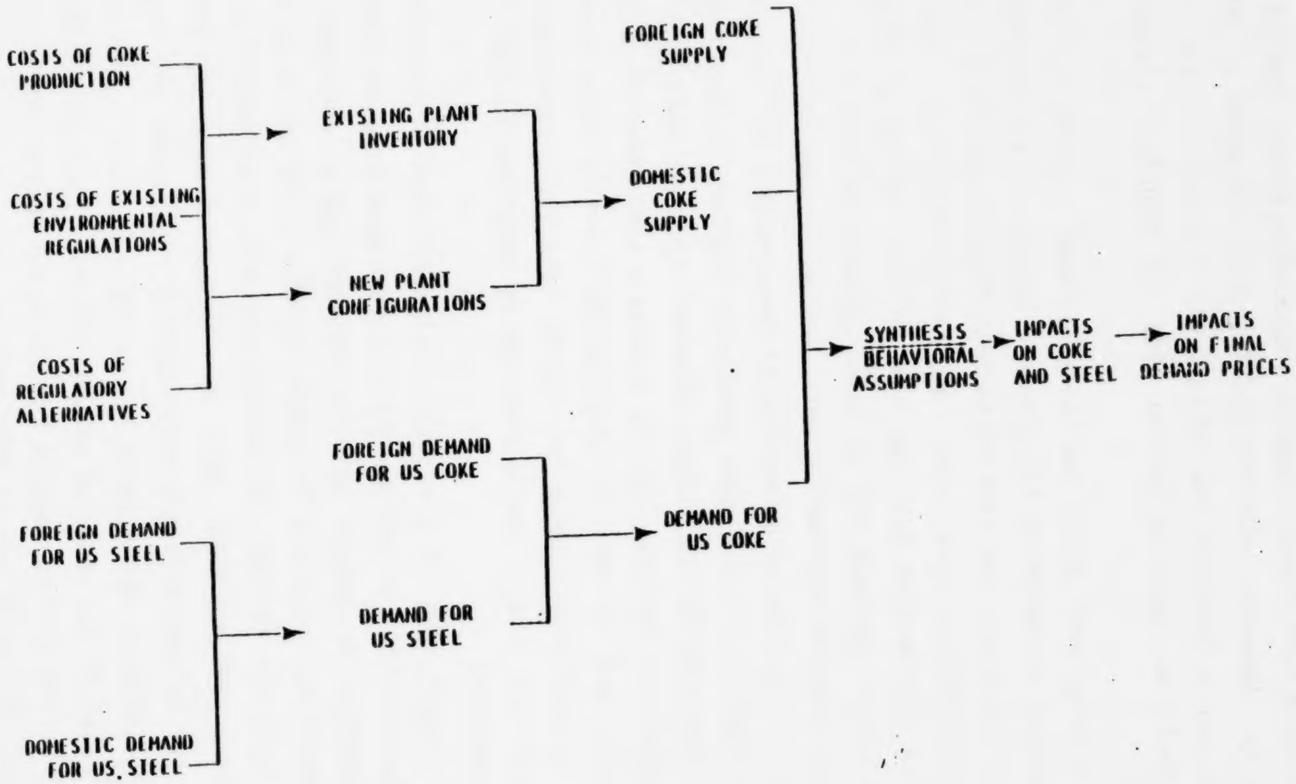
COSTS OF COKE PRODUCTION
COSTS OF EXISTING ENVIRONMENTAL REGULATIONS
COSTS OF REGULATORY ALTERNATIVES
EXISTING PLANT INVENTORY
NEW PLANT CONFIGURATIONS
FOREIGN COKE SUPPLY
DOMESTIC COKE SUPPLY
FOREIGN DEMAND FOR US STEEL
DOMESTIC DEMAND FOR US. STEEL
FOREIGN DEMAND FOR US COKE
DEMAND FOR US STEEL
DEMAND FOR US COKE
SYNTHESIS
BEHAVIORAL ASSUMPTIONS
IMPACTS ON COKE AND STEEL
IMPACTS ON FINAL DEMAND PRICES

Figure C-3. Economic impact model.

This approach provides a method of estimating the industry supply curve for coke, which shows the alternative coke quantities that will be placed on the market at alternative prices. When the supply curve is considered in conjunction with the demand curve, an equilibrium price and coke output rate can be projected. Supply curve shifts caused by the regulatory alternatives can be developed from the compliance cost estimates made by the engineering contractor. These new supply functions, along with the demand curve, then can be used to compute the equilibrium price and output rate under each regulatory alternative.

C.2.2.1.1 Data base. Plant-by-plant data on more than 60 variables for furnace and foundry coke plants in existence in 1979 were compiled from government publications, industry contacts, and previous studies of the coke industry. The data base was sent to the American Iron and Steel Institute (AISI), which submitted it to their members for verification, corrections, and additions,[79] and to the American Coke and Coal Chemicals Institute (ACCCI). The data were adjusted to account for the 1984 plant inventory in the reanalysis. Capacity, number of ovens, and status (hot idle, cold idle, under construction, or online) were updated for each battery.[5]

C.2.2.1.2 Output relationships. For a given battery, the full capacity output of coke, measured in megagrams per year (Mg/yr), is dependent on the nominal coal charge (megagrams of coal per charge) per oven, the number of ovens, and the effective gross coking time (net coking time plus decarbonization time). The following values for effective gross coking time were used except where plant-specific values were available.[78]

	Furnace coke	Foundry coke
Wet coal	18 h	30 h
Preheated coal	13 h	24 h

An age-specific outage rate that varies from 4 to 10 percent is assumed to allow for normal maintenance and repair. Thus, the model assumes some increase in such costs as a plant's age.

The quantities of by-products produced are estimated from engineering relationships. These quantities depend on the amount of coal carbonized, percentage of coal volatile matter, coking time, and configuration of the by-product facility at a plant. The by-products included in the model are coke breeze, coke-oven gas, tar, crude light oil, benzene-toluene-xylene (BTX), ammonium sulfate, anhydrous ammonia, elemental sulfur, sodium phenolate, benzene, toluene, xylene, naphthalene, and solvent naphtha. All plants are assumed to produce breeze and coke-oven gas.

C.2.2.1.3 Operating costs. The major costs of operation for a coke plant are expenditures for coal, labor, utilities, and chemicals. The activities within the coke plant were allocated to 5 production and 10 environmental control cost centers (Figure C-4) to facilitate the development of the operating cost estimates.

Coal is the major operating cost item in coke production. Plant-specific estimates of the delivered price of coal were developed by identifying the mine that supplies each plant and estimating transportation costs from the mine to the plant. When it was not known which coal mine supplied a particular plant, it was assumed that the coal came from the nearest mines supplying coal of the same volatile matter and ash content as that used by the plant. Transportation cost estimates were based on the distances traveled and the transport mode (barge or rail) employed.

Maintenance labor and supervision requirements were estimated for 69 jobs within the coke plant. Primary variables that determine the number of maintenance labor and supervision man-hours needed include type of plant (merchant or captive), number of battery units, number of plants at a site, size of by-product plant, type of coal charge (wet or preheated), and coke production. The labor rates used for captive plants were \$23.21/h for supervisory positions and \$21.38/h for production labor. For merchant plants, rates of \$21.52/h and \$19.61/h were assumed. These values represent numbers used in the 1979 analysis and scaled by the GNP implicit price deflator to 1984 dollars for the reanalysis.

The major utilities at a coke plant are steam, electricity, water, and other fuels. Utility requirements were estimated from the data on the plant configuration and output rates for coke and the by-products. The prices used for the utilities are \$7.41/10^3 lb steam; \$0.037/kWh electricity; \$0.22/10^3 gal cooling water; and \$3.76/10^6 Btu underfire gas. These values are the original 1979 figures scaled to 1984 dollars by the GNP implicit price deflator for the reanalysis.

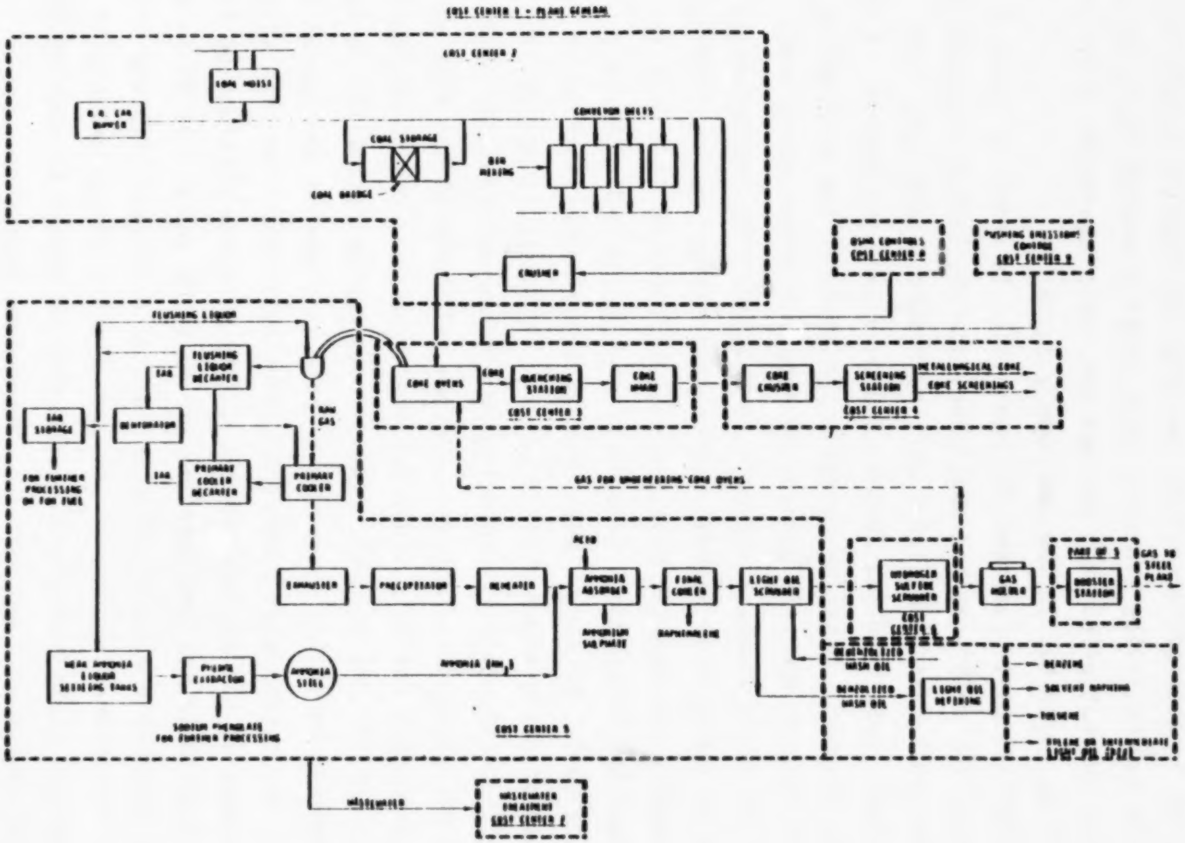
COST CENTER 1 - PLANT GENERAL
COST CENTER 2
R.R. CAR DUMPER
COAL HOIST
COAL STORAGE
COAL BRIDGE
OIL MIXING
CONVEYOR BELTS
CRUSHER
OSHA CONTROLS
COST CENTER 8
PUSHING EMISSIONS CONTROL
COST CENTER 9
FLUSHING LIQUOR
FLUSHING LIQUOR DECANTER
TAR
TAR STORAGE
DEHYDRATOR
TAR
FOR FURTHER PROCESSING OR FOR FUEL
PRIMARY COOLER DECANTER
PRIMARY COOLER
RAW GAS
COKE OVENS
COKE
QUENCHING STATION
COKE WHARF
COST CENTER 3
COKE CRUSHER
SCREENING STATION
METALLURGICAL COKE
COKE SCREENINGS
COST CENTER 4
GAS FOR UNDERFIRING COKE OVENS
EXHAUSTER
PRECIPITATOR
REHEATER
ACID
AMMONIA ABSORBER
AMMONIUM SULPHATE
FINAL COOLER
NAPHTHALENE
LIGHT OIL SCRUBBER
HYDROGEN SULFIDE SCRUBBER
COST CENTER 6
GAS HOLDER
PART OF 5
BOOSTER STATION
GAS TO STEEL PLANT
DEBENZOLIZED WASH OIL
BENZOLIZED WASH OIL
LIGHT OIL REFINING
BENZENE
SOLVENT NAPHTHA
TOLUENE
XYLENE OR INTERMEDIATE LIGHT OIL STILL
WEAK AMMONIA LIQUOR SETTLING TANKS
PYRIDINE EXTRACTOR
SODIUM PHENOLATE FOR FURTHER PROCESSING
AMMONIA STILL
AMMONIA (NH3)
COST CENTER 5
WASTEWATER
WASTEWATER TREATMENT
COST CENTER 7

Figure C-4. Coke plant cost centers.

C.2.2.1.4 Capital costs. Although no net additions to industry coke-making capacity are anticipated during the 1984 to 1995 period, a number of producers had plans to rebuild or replace existing batteries in 1979. In 1984, three new batteries had been constructed and one was under construction.[5] Such actions alter the long-run industry supply curve because the new batteries typically have lower operating costs per unit of output than the batteries they replace and, most important, their capital costs will be reflected in the new supply curve.

The capital cost breakdown for new plants is shown in Table C-16. For such plants, the major capital cost items are the battery, quench tower, quench car, pusher machine, larry car, door machine and coke guide, by-product plant, coal-handling system, and coke-handling system. A 60-oven battery is assumed. Pipeline charging can increase the coke-making capacity of a given oven by about 25 percent by reducing gross coking time. Consequently, the per-unit operating cost is reduced. The capital costs show economies of scale, i.e., larger plants have smaller per-unit-of-capacity capital costs. The capital cost per unit of capacity is higher for pipeline-charged batteries than for conventionally charged batteries.

Periodically, batteries must undergo major rehabilitation or rebuilding because of performance deterioration. The costs of pad-up rebuilds will vary from site to site depending on battery maintenance, past operating practices, and other factors. Average estimates of the cost of rebuilding were developed for this study and are shown in a report by PEDCo Environmental, Inc.[81] The economic life of coke-making facilities is subject to considerable variation depending on past maintenance and operating practices, which also affect current operating costs. For this study, 25 years was used as the average preferred life of a new coke-making facility; however, many batteries are operated for 35 to 40 years. If 35 to 40 years is a more reasonable battery lifetime, use of a 25-year lifetime will result in some overestimation of the annual costs of new or rebuilt facilities. However, firms probably will not plan or expect to wait 35 to 40 years to recoup an investment in coke-making capacity.

C.2.2.1.5 Environmental costs. Plant-specific estimates of the installed capital and operating costs for current environmental regulations

TABLE C-16. ESTIMATED CAPITAL COSTS OF NEW PLANTS[80]

	Conventionally charged battery		Pipeline charged battery	
	4-m[a]	6-m[a]	4-m[a]	6-m[a]
Capacity (10^3 Mg/yr)	450	720	560	900
Capital costs by element (10^6 1979 dollars)				
Coke battery	34.20	48.90	64.60	83.70
Quench tower with baffles	2.45	2.85	2.45	2.85
Quench car and pushing emissions control	6.58	7.92	6.58	7.92
Pusher machine	2.50	3.20	2.40	3.20
Air-conditioned larry car	1.72	2.28	0.00	0.00
Door machine and coke guide	1.80	2.10	1.80	2.10
By-product plant	32.50	39.75	35.76	43.74
Coal-handling system	18.20	23.60	20.62	26.70
Coke-handling system	6.85	8.80	7.74	10.00
Offsites	1.60	1.80	1.69	1.91
Total	$108.40	$141.20	$143.74	$182.12

[a] In the production cost model, new foundry batteries were assumed to be 4-m batteries and new furnace batteries were assumed to be 6-m batteries.

and the regulatory alternatives under consideration in this study were incorporated in the model. In the reanalysis, the current regulations are assumed to include workplace standards (Occupational Safety and Health Administration [OSHA]), water quality regulations (best practicable technology [BPT] and best available technology [BAT]), and State implementation plan (SIP) requirements. Compliance expenses incurred for all plants in the data base for each of the current regulations assumed baseline control costs were estimated. Costs to comply with OSHA and BPT water requirements under the Federal Water Pollution Control Act were assumed incurred by 1981. Costs for all other baseline environmental regulations were assumed to be incurred by 1983.

The scatter diagrams in Figures C-5 and C-6 show estimates from the coke supply model of average total cost of production in 1984, including environmental costs, for all furnace and foundry coke plants. A weak, inverse relationship between the average cost of production and the size of the plant is evident in Figures C-5 and C-6. However, a number of other factors create variability in the average cost of production across coke plants. The most important of these factors are the delivered price of coal, the age of the plant, and the by-products recovered.

C.2.2.1.6 Coke supply function--existing facilities. The operating and capital cost functions were used to estimate the cost of production, including relevant environmental costs, for all plants in the data base. This cost does not include a return on investment for existing facilities. The capital costs for these facilities already have been incurred and do not affect operating decisions.

Capital costs that have not yet been incurred are annualized at 6.2 percent, which is estimated to be the real (net of inflation) cost of capital for the coke industry. (This percentage is an after-tax estimate.) This figure, which was estimated from data on the capital structure for publicly owned steel companies, has been used in this study as the minimum acceptable rate of return on new facilities.[82]

The regulatory alternatives for coke-oven by-product plants involve control equipment that is not affixed to batteries. Accordingly, the equipment is not affected by battery age or size (height) of the battery

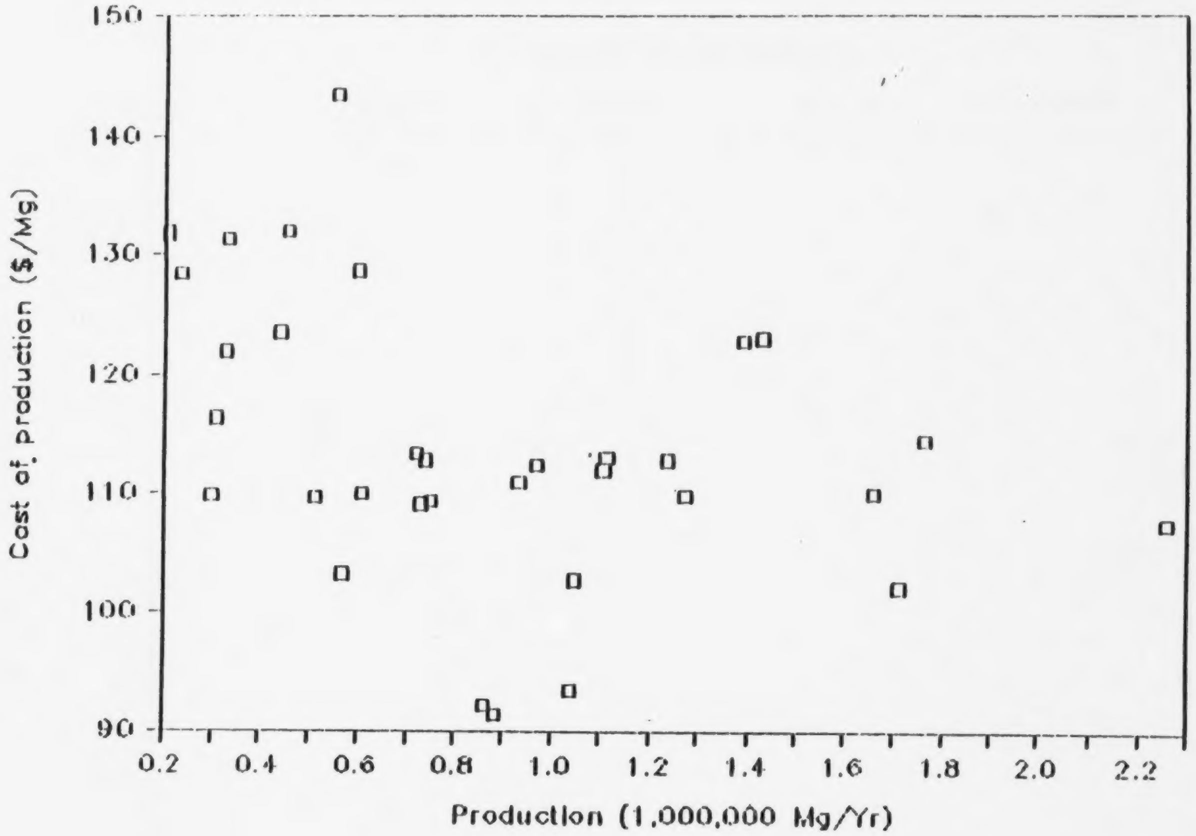

Figure C-5. Estimated average cost of furnace coke production as a function of plant production, 1984.

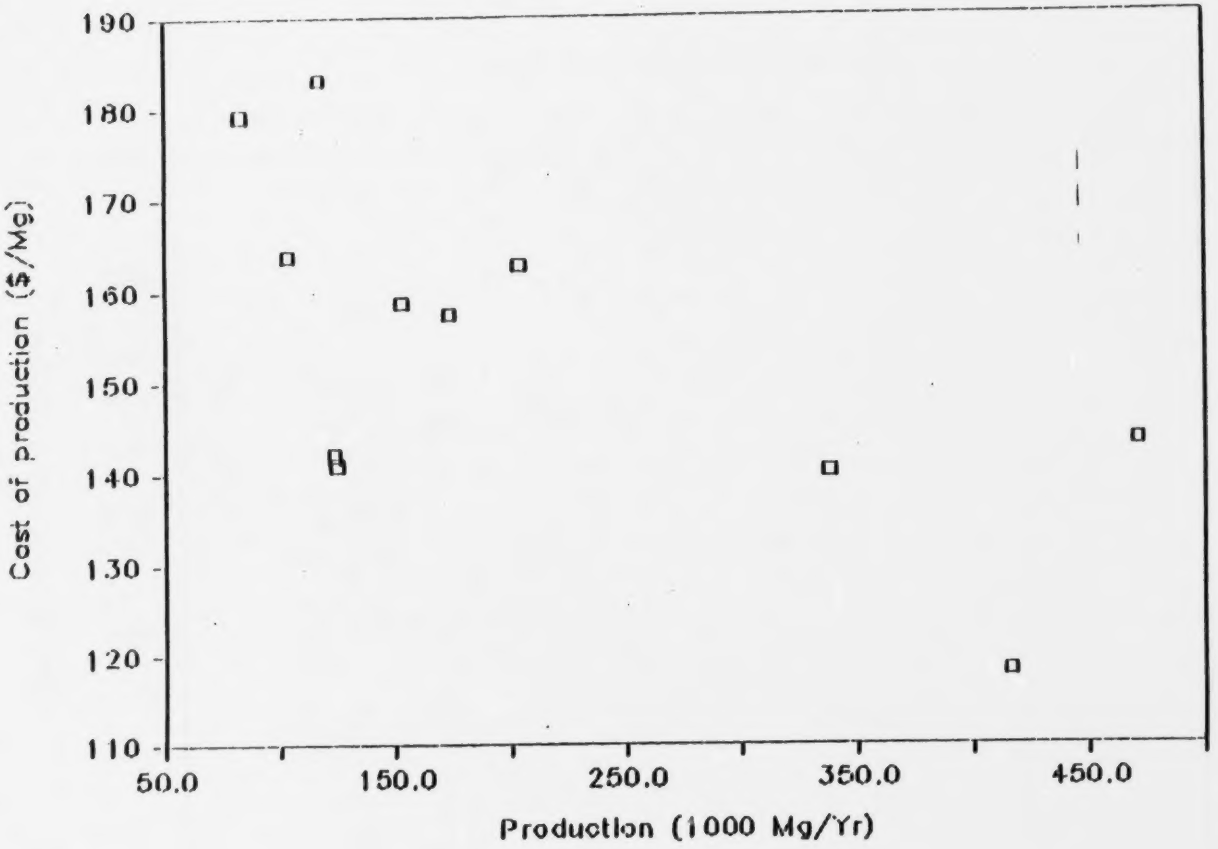

Figure C-6. Estimated average cost of foundry coke production as a function of plant production, 1984.

replacement. The capital costs of the regulatory alternatives are annualized over the life of the control equipment (20 years). This action is tantamount to assuming either that all by-product plants have a remaining life of at least 20 years or that the control equipment is salvageable.

The supply function for each plant is estimated as follows: the average cost of production is computed for each battery in the plant; these batteries are arranged in increasing order of their average costs of production, and the output for each battery is accumulated to produce a stepped marginal cost function for the plant; plant overhead costs are averaged for all relevant plant output rates; and average total costs are computed for each output rate by summing the average costs for plant overhead and the battery. Each plant's supply function is the portion of the marginal cost function above the average total cost function. For existing plants where the average total cost exceeds marginal cost over the entire range of output, the supply function is the point on the plant's average total cost function represented by capacity output (after allowing for outages). The aggregate long-run supply function for all currently existing coke plants and batteries is obtained by horizontally summing the supply function for each plant. The 1984 industry marginal cost (supply) curves for existing furnace and foundry coke plants are presented in Figures C-7 and C-8, respectively.

C.2.2.1.7 Coke supply function--new facilities. The cost of coke production for new furnace and foundry batteries was estimated from the engineering cost model, assuming the new model plants described previously. These costs include the normal return on investment and allowances for depreciation and corporate income taxes. When expressed on a per-unit basis, these costs are the minimum price at which it is attractive to build new facilities.

C.2.2.2 Demand Side. The demand for coke is derived from the demand for products that use coke as an input to production--primarily steel and ferrous foundry products. A demand function for furnace coke was derived by econometrically modeling the impacts of changes in furnace coke production costs on the steel industry.[83]

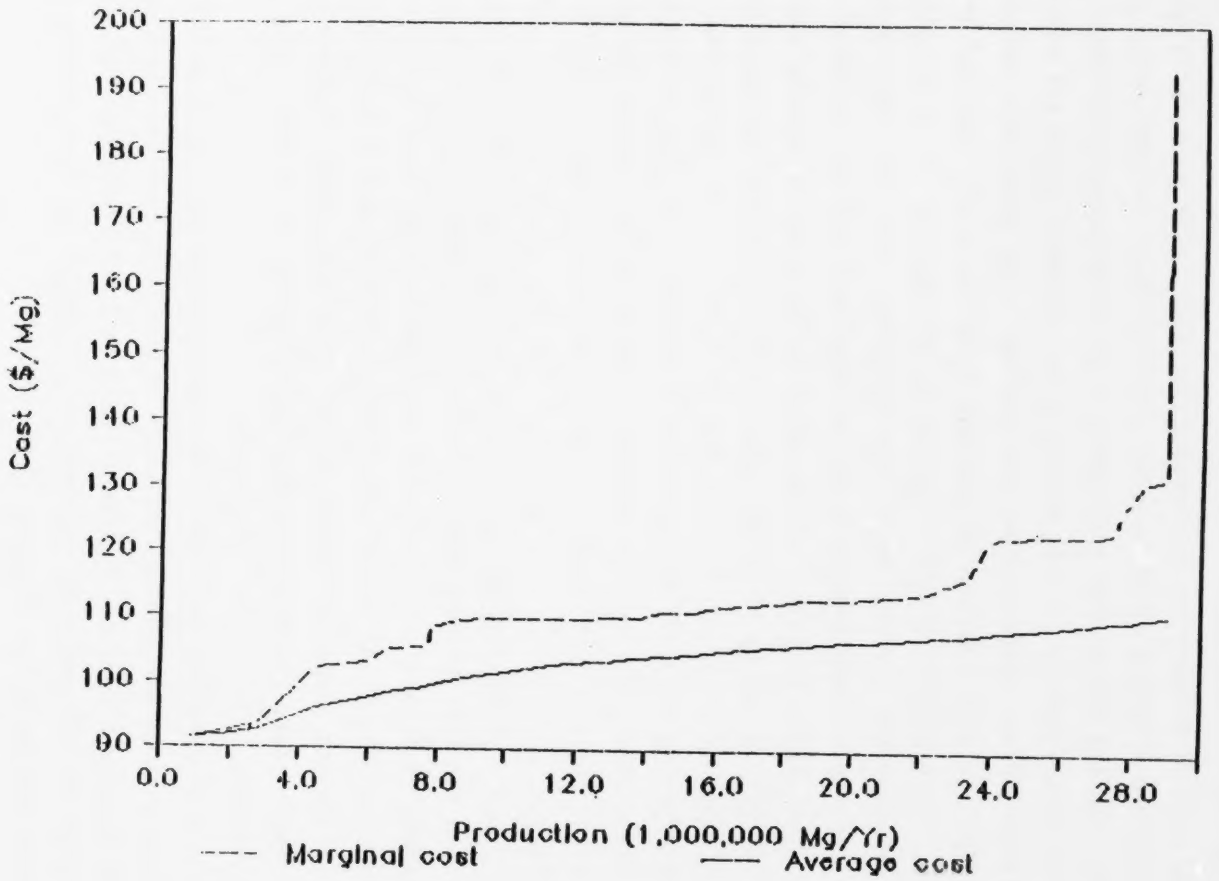

Figure C-7. Marginal and average cost functions for furnace coke, 1984.

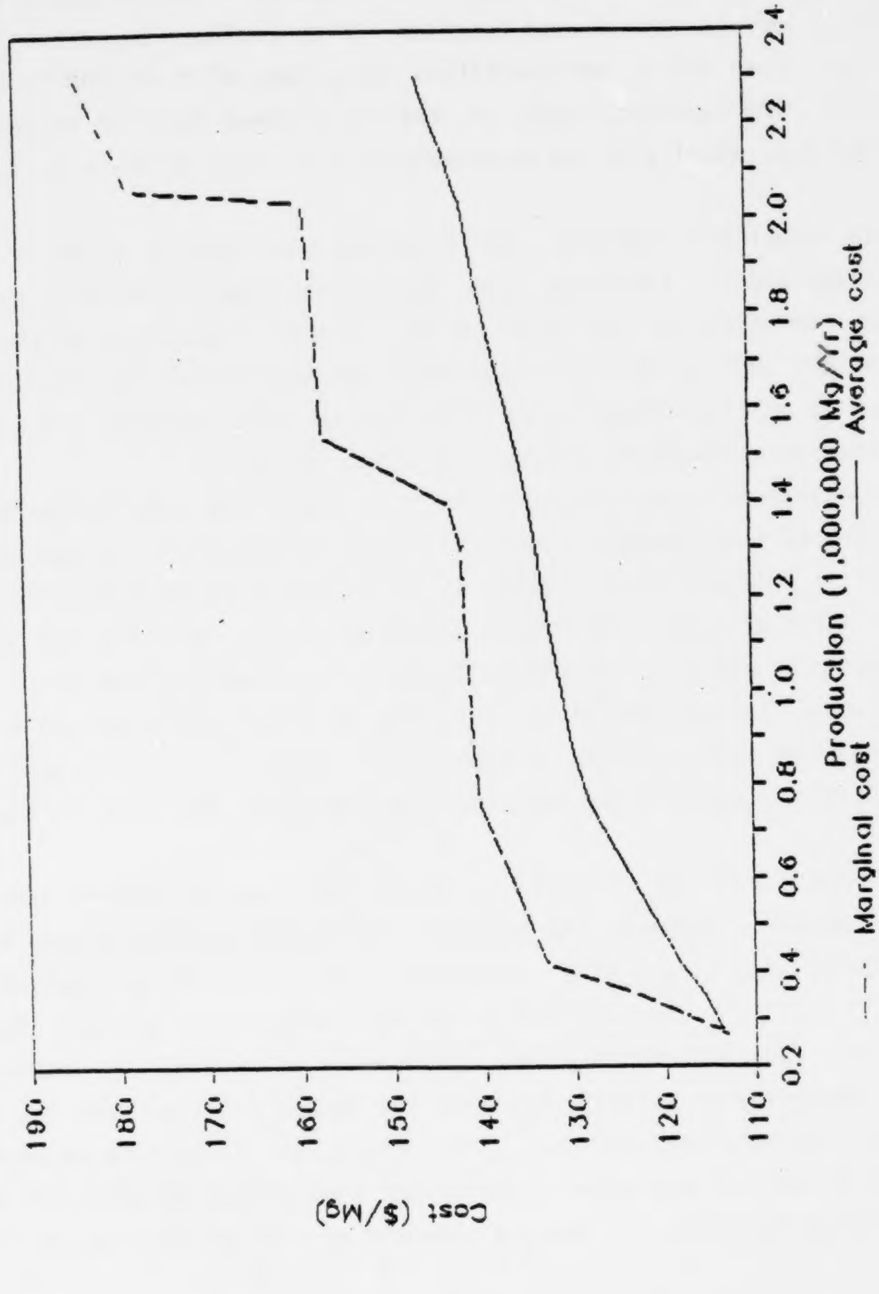

Figure C-8. Marginal and average cost functions for foundry coke, 1984.

The econometric model of the steel industry has two sectors: steel and coke. The steel sector includes domestic steel supply, steel imports and exports, and steel consumption (steel supply plus imports minus exports). Similarly, the model of the coke sector consists of domestic coke supply, domestic coke demand, and coke imports and exports. The two sectors are linked by a derived coke demand function, which includes as variables steel production, steel price, and quantities and prices of other inputs to steel production. The domestic supply of steel is assumed equal to domestic demand for U.S. steel plus world demand for U.S. steel minus U.S. import demand.

Both linear and nonlinear specifications were used to estimate the steel-sector model. Two-stage least squares was used to estimate the different components of the steel sector. Visual inspections of the correlation matrix and a plot of the dependent variable versus the residuals indicated no multicollinearity or heteroscedasticity problems. The Durbin-Watson statistic showed no evidence of autocorrelation.

The econometric estimation of the coke sector was complicated by the small share of total domestic production that is traded in the market. The fact that very little coke is actually sold creates concern over the reported price of coke. Therefore, estimates of the implied price of coke were developed, based on the value of coke in steelmaking, and used in the estimation of elasticities.[84] [85] Estimates of elasticities for coke and steel functions are presented in Table C-17. Actual prices for coke produced and used internally by the producing companies were used in the reanalysis.

An attempt was made to derive a demand function for foundry coke in an analogous manner. However, the relevant coefficient estimates were not statistically significant at a reasonable level. A direct estimation of the demand function, based on the prices of foundry coke, foundry coke substitutes, and complementary inputs, also was attempted. Unfortunately, the data necessary to properly estimate the demand function were not readily available from published sources. Accordingly, the elasticity of demand for foundry coke was estimated based on the theoretical relationship between the production function for foundry products and the derived demand function

TABLE C-17. ESTIMATES OF ELASTICITIES OF STEEL AND COKE MARKETS

		Point estimate	Interval estimate[a]
1.	Percent change in furnace coke demand for 1 percent change in the price of furnace coke	-1.29[b]	--[c]
2.	Percent change in foundry coke demand for 1 percent change in the price of foundry coke	-1.03[c]	--[c]
3.	Percent change in import demand for 1 percent change in the price of furnace coke	1.88	(-1.68, 5.44)
4.	Percent change in price of steel for 1 percent change in the price of furnace coke	0.11[c]	--[c]
5.	Percent change in steel demand for percent change in the price of steel	-1.86[d]	(-0.54, -3.18)
6.	Percent change in steel imports for 1 percent change in the price of steel	1.51[d]	(0.51, 2.51)

Note: Estimates are based on the empirical analysis using annual data for the years 1950-1977 with a structural econometric model of steel and coke markets.

[a] Interval estimates are based on 95 percent confidence level.

[b] Derived from the production function for steel, and input cost shares.

[c] Calculation based on the theoretical relationship between input demand elasticity and input cost share in the production of outputs. Accordingly, no interval is provided.

[d] Significantly different from zero at 1 percent level of statistical significance.

for inputs to foundry production. This elasticity calculation is based on a 3-year average of the cost share of foundry coke in foundry production. This estimate is presented in Table C-17. This elasticity assumes U.S. demand for foundry coke is supplied entirely from domestic production (Scenario A).

Another scenario is that imported foundry coke competes with the domestic product in the open market (Scenario B). A simplifying assumption is that they are perfect substitutes in the production processes that utilize foundry coke. In this case, a reduction in U.S. supply is compensated by imports, so that price need not rise if the quantity of imports purchased is increased. Both scenarios are examined in the reanalysis.

C.2.2.3 Synthesis. Separate linear functions were fit to the furnace and foundry coke marginal cost values depicted in Figures C-7 and C-8. As illustrated in Figures C-9 and C-10, each supply function is used with the demand function for the appropriate type of coke to compute the initial equilibrium price-quantity values (P_1 and Q_1 in Figures C-9 and C-10). In the case where imports are not perfect substitutes for domestically produced coke, the supply function is reestimated for each regulatory alternative (S_2 in Figure C-9), and the new equilibrium price-quantity values (P_2 and Q_2 in Figure C-9) are predicted.

The case where imports compete with domestically produced foundry coke is shown in Figure C-10. As in Figure C-9, the supply curve shifts backward to S_2. However, because imports are available, no change in price and quantity need be experienced by the consumer. Although domestic production is reduced by Q_1-Q_2, the share of the market supplied by imports increases by this same amount. The new equilibrium price and quantity for domestic coke are P_1 and Q_2 in Figure C-10.

C.2.2.4 Economic Impact Variables. Table C-18 shows the specific economic variables for which impacts are estimated. The methodology presented previously was designed to provide industry-level estimates of these impacts. The conventional demand and supply partial equilibrium model of a competitive market was chosen for this analysis because it was believed to represent the key characteristics of the coke market and many of the impacts of interest can be estimated readily from this model.

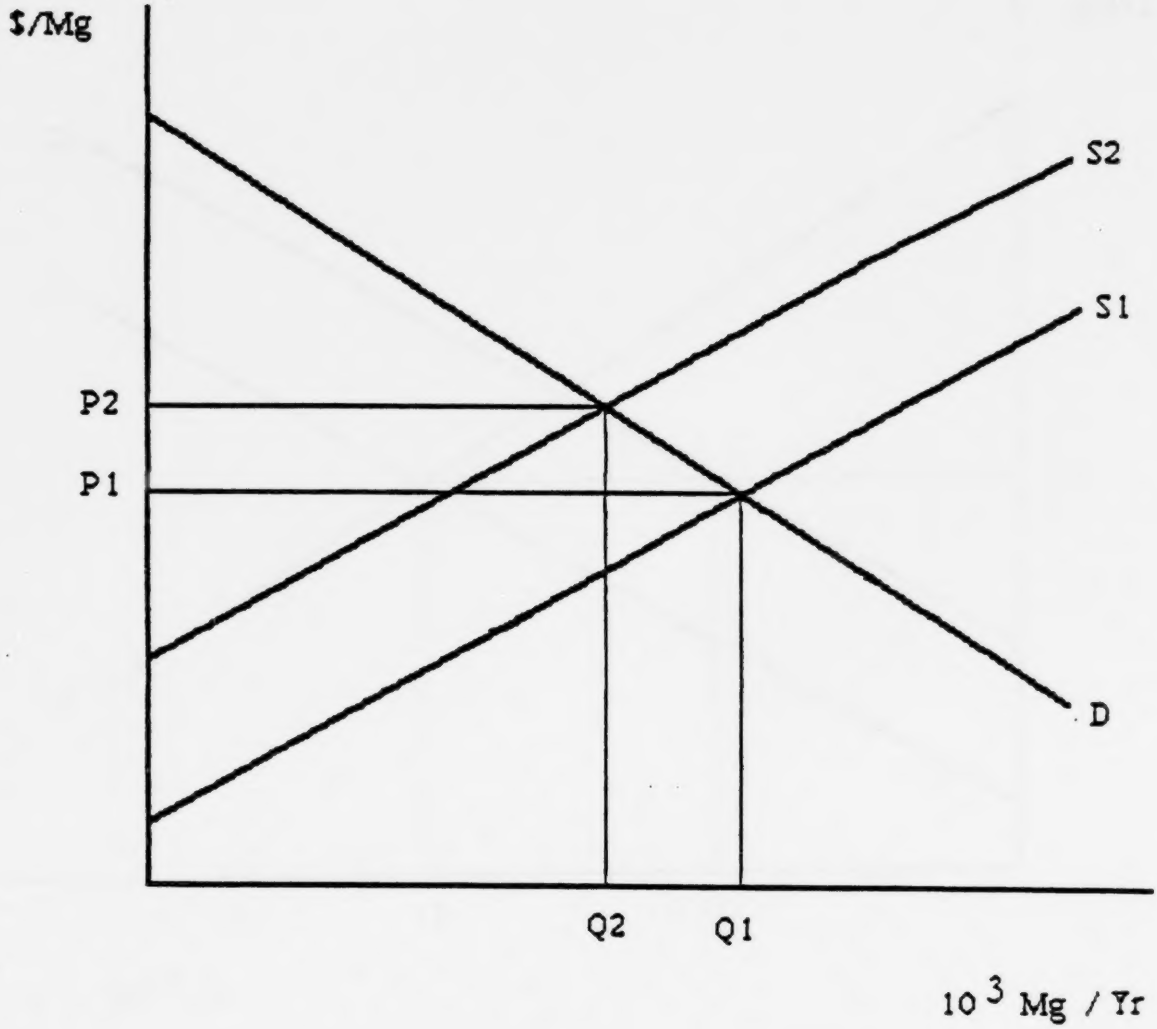

Figure C-9. Coke supply and demand without import competition.

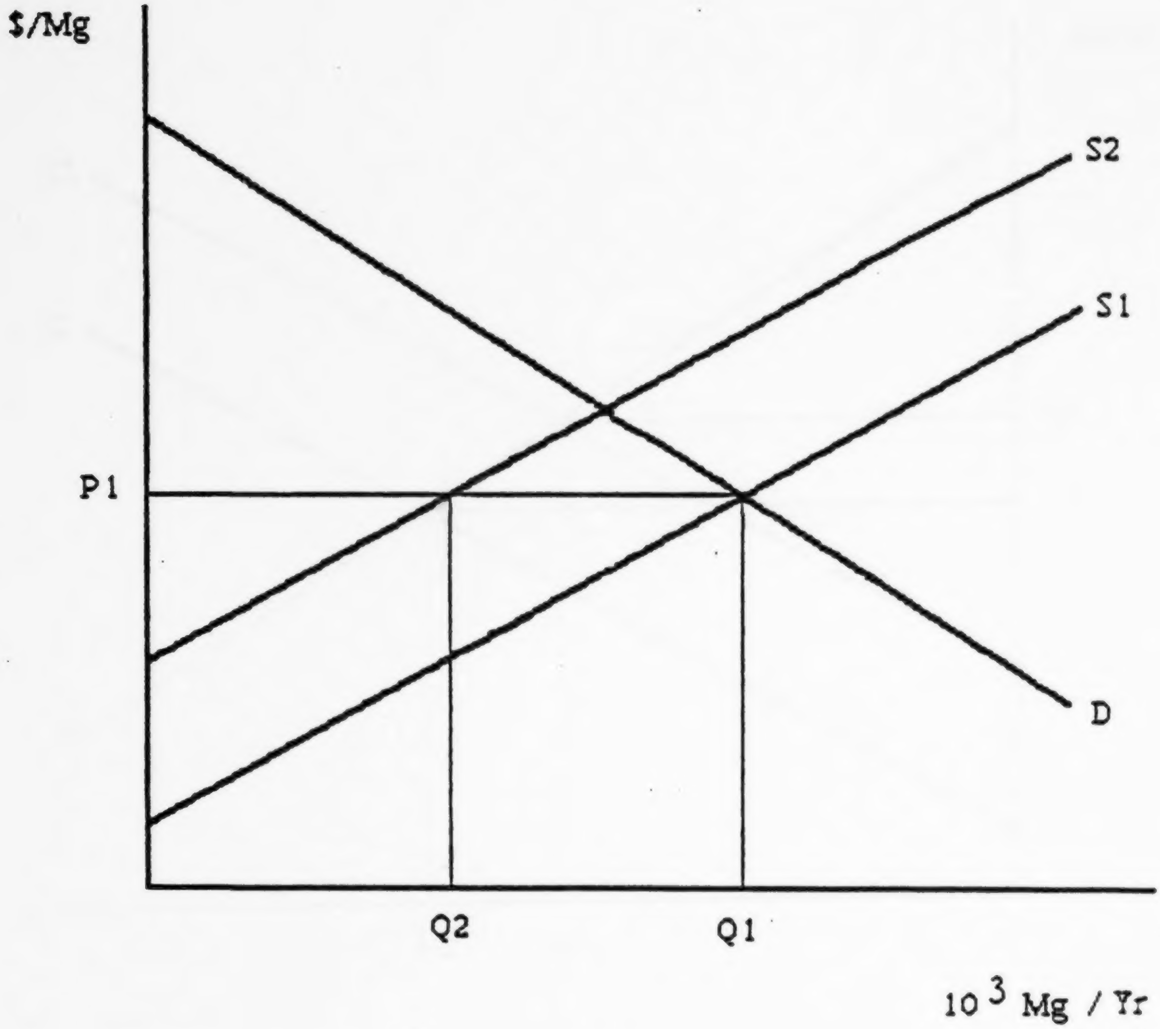

Figure C-10. Coke supply and demand with import competition.

TABLE C-18. ECONOMIC IMPACT VARIABLES AND AFFECTED SECTORS

	Sector			
Variable	Furnace coke	Foundry coke	Steel	Final demand
Price	X	X	X	X
Output	X	X	X	
Profits	X	X		
Costs	X	X		
Plant closures/openings	X			
Capital requirements	X	X		
Factor employment				
Labor	X	X		
Metallurgical coal	X	X		
Imports	X	X[a]	X	

[a] Impacted under Scenario B.

Figure C-11 represents the markets for furnace coke and for foundry coke which is free of import competition (Scenario A). Figure C-12 describes the market for foundry coke that must compete with imported coke, which is assumed to be a perfect substitute for domestic coke (Scenario B). In Figure C-11, D represents the derived demand for coke. The line S_1 represents the baseline supply curve for coke. The equilibrium price and quantity are P_1 and Q_1, respectively. The area c_1+g+h is the total cost of coke production, b+c_1+c_2+e+g+h is the total revenue, and b+c_2+e represents before-tax profits. The total cost of coke production (c_1+g+h) can be divided into costs incurred to produce coke per se and the costs being incurred to meet baseline environmental regulations.

The regulatory alternatives will increase the cost of coke production by shifting the supply function to S_2. This is not a parallel shift because of the small magnitude of changes and the continued production by uneconomic firms. Given the demand and supply functions as drawn in Figure C-11, higher costs of production will lead to higher prices. A production decrease as shown in Figure C-11 would cause price to rise to P_2 and the quantity demanded to fall to Q_2. The actual costs to the producer of the regulatory alternative are c_2+d-c_1, and profits before income taxes are a+b+c_1.

Costs to consumers are represented by a+d+f, the amount that consumers paid to purchase the amount (Q_1-Q_2) at price P_1 before the regulation, but now must pay price P_2 to purchase.

In Figure C-12, D represents derived demand for coke and S_1 represents the baseline supply curve for coke, with P_1 and Q_1 representing equilibrium price and quantity

As in Figure C-11, area c_1+g+h is the total cost of coke production, including expenses incurred to meet baseline environmental regulations. Area b+c_1+c_2+e+g+h is the total revenue, and b+c_2+e is before-tax profits.

The regulatory alternatives shift the supply function to S_2. As explained, this is not a parallel shift. In this scenario, price does not rise even though domestic production is reduced. Instead, because imported coke is assumed to be a perfect substitute for domestic coke and because imported coke is assumed to be available at price P_1, domestic consumers purchase more imports and less domestic coke. The results are that domestic

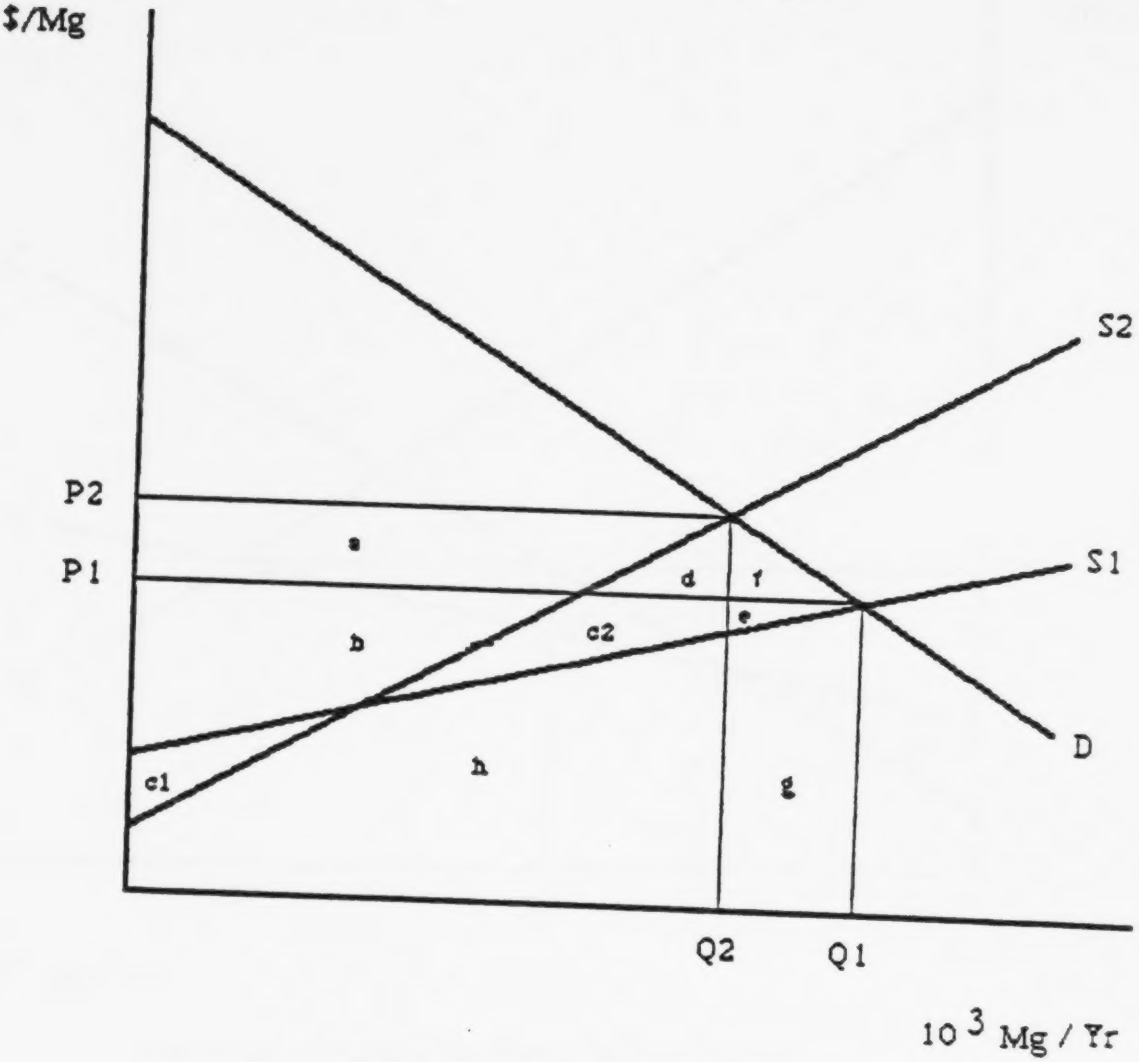

Figure C-11. Coke demand and supply with and without regulatory alternatives, without import competition.

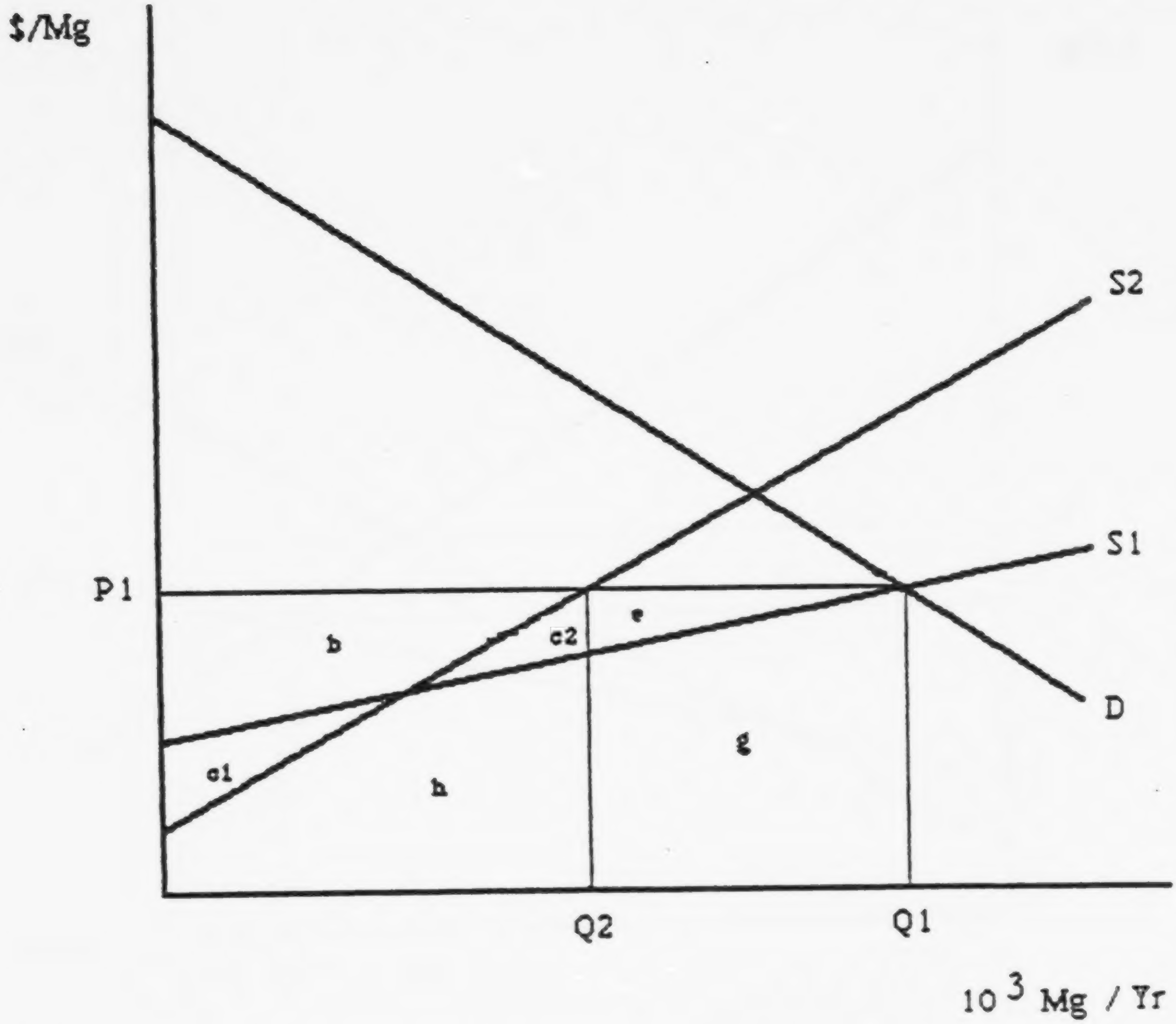

Figure C-12. Coke demand and supply with and without regulatory alternatives, with import competition.

production decreases to Q_2, imports increase by Q_1-Q_2, and price remains at P_1, as shown in Figure C-12.

The costs of the regulation to the producer are c_2-c_1. Total revenue is b+c_1+c_2+h, and production costs are h+c_2. Profits before income taxes are b+c_1. There are no costs to consumers because they are able to purchase quantity Q_1 at price P_1 as they were before the regulation.

C.2.3 Furnace Coke Impacts

As described in Section C.2.2 of this analysis, the furnace coke industry has been modeled as a competitive industry supplying coke to the steel industry. This definition implies the existence of interfirm and intrafirm shipments of coke. However, no allowance has been made for coke transportation costs, although coal transportation costs are included in the cost of coke production estimates. Coke plants and their associated steel mills are typically clustered together. As noted in Section C.1.4.1, most coke is consumed within the region where it is produced. Hence, transportation across great distances is uncommon. Therefore, the omission of coke transport costs should not greatly influence the calculations.

The baseline values for 1983, presented in Table C-19, are actual data for 1983, except for coke prices, which are calculated by the model. The values for 1983 are assumed to reflect full compliance with applicable SIP and OSHA air quality regulations and water quality regulations. The coke supply model was used to compute the price of furnace coke, costs, revenues, and profits, given these actual values. Coal consumption and employment projections were made using current coal- and labor-output ratios. The supply function was reestimated assuming control levels being practiced in 1984 for all emission sources. This estimation was used to determine the impacts of moving from baseline industry control levels to alternative regulations control for all sources.

Table C-20 presents total costs incurred by companies in SIC 3312 in meeting environmental regulations up to 1983. These costs represent industry efforts to achieve baseline compliance. Expenditures are segmented by type of pollutant treated. Total cost for abatement increased throughout the late 1970's and peaked at $956.5 million (1972 dollars) in 1979. Expenditures declined slightly in 1980 and 1981 and dropped to an 8-year low of $549.8 million (1972 dollars) in 1982.

TABLE C-19. BASELINE VALUES FOR ECONOMIC IMPACT ANALYSIS--FURNACE COKE, 1983[37 86 87]

	Baseline values[a]
Coke market	
Price (1983 \$/Mg)	106.25[b]
Production (10^3 Mg)	20,462
Consumption (10^3 Mg)	24,380
Imports (10^3 Mg)[c]	3,918
Employment (jobs)[d]	6,236
Coal consumption (10^3 Mg)	29,787
Steel market	
Price (1983 \$/Mg)	319.97
Production (10^3 Mg)	76,763
Consumption (10^3 Mg)	75,710
Imports (10^3 Mg)	15,486
Employment (jobs)[e]	295,000

[a] Baseline assumes companies meet existing regulations including OSHA (coke-oven emissions); State regulations on desulfurization, pushing, coal handling, coke handling, quench tower, and battery stack controls; and BPT and BAT water regulations.

[b] Calculated. Market price for furnace coke was $123.51 in the fourth quarter of 1983.

[c] Calculated. Imports = Consumption - production.

[d] Calculated. Furnace coke employment = Employment in byproduct coke industry × proportion of coke production represented by furnace coke sector.

[e] Represented by employment in SIC 3312 (Blast furnaces and steel mills).

TABLE C-20. POLLUTION ABATEMENT EXPENDITURES FOR SIC 3312[62]

	Abatement expenditures, 10^6 current $					
Year	Air pollution	Water pollution[c]	Solid waste[d]	Recovered cost, 10^6 current $	Total cost,[a] 10^6 current $	Total cost,[b] 10^6 1972 $
1975	477.3	306.8	43.1	18.1	809.1	647.3
1976	606.9	309.5	51.4	17.8	950.0	722.0
1977	675.1	385.8	85.5	18.1	1,128.3	812.4
1978	709.1	424.9	111.2	15.1	1,230.1	824.2
1979	932.6	511.6	99.5	1.0	1,542.7	956.5
1980	925.4	494.9	127.9	18.8	1,529.4	856.5
1981	940.9	512.6	153.0	22.3	1,584.2	807.9
1982	666.8	408.3	92.4	22.0	1,145.5	549.8

[a] Total cost = Capital expenditure + operating costs - recovered cost summed for all pollutants.

[b] Implicit price deflator for the nonfarm business sector used to convert current dollars to 1972 values.

[c] Includes payments to government units for public sewage use.

[d] Includes payments to government units for solid waste collection and disposal.

C.2.3.1 Price Effects. The price of furnace coke is assumed to be established in a competitive market. In the basic model of a competitive market, the interaction of supply and demand determine the equilibrium price. This price is dependent on the costs of production of the marginal producer and the value of the product to the marginal buyer. The marginal producer is the producer who is willing to supply the commodity at the market price because he is just covering all his costs at that price. The marginal buyer is just willing to pay the market price. Other buyers who value the product more still pay only the market price.

Estimates of the demand and supply functions for furnace coke are necessary to develop projections of the equilibrium price for furnace coke with and without increased control. The supply of furnace coke as shown previously would be shifted by the regulatory alternatives. The demand for furnace coke has been econometrically estimated and found to be responsive to price changes. The estimated elasticity of demand for furnace coke is -1.3. This responsiveness reflects the substitution of other fuels for coke in blast furnaces; the substitution of other inputs, primarily scrap, for pig iron in steelmaking; and the substitution of other commodities for steel throughout the economy.

Higher prices for coke will increase the cost of steel production unless there is a perfect substitution between coke and other inputs to steelmaking. In that case, the consumption of coke would decrease to zero. If substitutions for coke in steelmaking were not possible (i.e., input proportions were fixed), the steel price increase would be the percentage change in coke price times the share that coke represents in the cost of steelmaking (10.7 percent) times the base price of steel.

Table C-21 presents the furnace coke and steel price impacts of the regulatory alternatives. The proposed regulatory alternatives raise coke prices only slightly: 0.12 percent for Alternative II, and 0.33 percent for Alternative III.

C.2.3.2 Production and Consumption Effects. The estimated demand and supply relationships for coke are used to project the production and consumption effects of the regulatory alternatives. As shown in Table C-22, the changes in coke production and consumption are fairly small for the two

TABLE C-21. PRICE EFFECTS OF REGULATORY ALTERNATIVES--FURNACE COKE, 1984[a]

Regulatory Alternative	Coke, $/Mg	Steel, $/Mg
II	0.13 (0.12)	0.04 (0.01)
III	0.36 (0.33)	0.12 (0.04)

[a] Values in parentheses are percentage changes from baseline.

TABLE C-22. PRODUCTION AND CONSUMPTION EFFECTS OF REGULATORY ALTERNATIVES--FURNACE COKE, 1984[a]

Regulatory Alternative	Coke market, 10^3 Mg/yr			Steel market, 10^3 Mg/yr		
	Production	Consumption	Imports	Production	Consumption	Imports
II	-32 (-0.16)	-23 (-0.09)	9 (0.23)	-21 (-0.03)	-18 (-0.02)	3 (0.02)
III	-90 (-0.44)	-65 (-0.26)	25 (0.64)	-60 (-0.08)	-51 (-0.07)	9 (0.06)

[a] Values in parentheses are percentage changes from baseline.

regulatory alternatives. For Alternative II, changes in production and consumption are less than 0.2 percent. For Alternative III, the quantity changes are less than 0.5 percent.

Imported coke is a close substitute for domestically produced coke. Imported coke is not a perfect substitute because coke quality deteriorates during transit and contractual arrangements between buyers and sellers are not costless. However, increases in the costs of production for domestic plants will increase the incentive to import coke.

The projected increases in coke imports are reported in Table C-21. Imports increase by 0.23 percent under Alternative II and 0.64 percent under Alternative III. As illustrated below, coke imports increased significantly since 1972, but peaked in 1979 and began a marked decline.

Year	Imports, 10^3 Mg
1972	168
1973	978
1974	3,211
1975	1,650
1976	1,189
1977	1,659
1978	5,191
1979	3,605
1980	598
1981	478
1982	109
1983	32

The increase in imports in the 1970's is believed to be the result of a coal strike in the United States during 1978 combined with depressed conditions in the market for steel in the countries exporting coke to the United States. Accordingly, future importation at a high level may depend on future market conditions for steel in other countries. In any case, the change in coke imports projected for all the regulatory alternatives is small.

C.2.3.3 Coal Consumption and Employment Effects. Any reductions in coke and steel production are expected to cause reductions in the use of the factors that produce them. The major inputs to coke production are coal and labor. Labor is also an important input in coal mining.

The coal consumption and employment implications of the projected reductions in coal, coke, and steel production are shown in Table C-23. For Regulatory Alternative II, coal consumption and employment impacts are less than 0.2 percent, while for Regulatory Alternative III, impacts are less than 0.5 percent. These values were developed assuming constant coal- and labor-output ratios. The employment impacts shown do not include the estimated increases in employment caused by the regulatory alternatives. Therefore, the employment impacts represent maximum values.

C.2.3.4 Financial Effects. The aggregate capital costs of the regulatory alternatives are summarized in Table C-24. Capital costs also have been summed across member plants to determine the cost to each coke-producing company of meeting alternative regulations. The total capital costs by company may be used to produce percentages that express the relation between total capital cost and the annual average net capital investment of the company and the annual cash flow of the company. This analysis is presented to give some insight into the distribution of the financial effects across coke-producing firms.

Total capital cost as a percentage of average annual net investment is an indicator of whether the usual sources of investment capital available to the firm will be sufficient to finance the additional capital costs caused by the regulatory alternatives. The larger this percentage, the greater the probability that investment needed to comply with the regulatory alternatives would significantly reduce investment in other areas. This percentage provides some insights regarding the degree to which firms will be able to finance the controls required to meet the regulatory alternatives without a serious impact on their financial position.

Total capital cost as a percentage of cash flow provides similar information. Cash flow data accounts for revenues, operating costs, depreciation, expenditures on dividends, interest expenses, and taxes. Thus, it is a more realistic measure of the funds available to the firm. However, this index may not be consistent across firms because depreciation accounting varies across firms. As with the net investment ratio, the larger the ratio, the greater the probability that cash flow will be diverted from other sources to finance compliance expenditures.

TABLE C-23. COAL CONSUMPTION AND EMPLOYMENT EFFECTS OF REGULATORY ALTERNATIVES--FURNACE COKE, 1984[a]

Regulatory Alternatives	Coal consumption for coke, 10^3 Mg/yr	Employment, jobs[b]		
		Coal[c] mining	Coke plant	Steel-making
II	-47 (-0.16)	-13 (-0.01)	-10 (-0.16)	-83 (-0.03)
III	-131 (-0.44)	-37 (-0.02)	-27 (-0.43)	-230 (-0.08)

[a] Values in parentheses are percentage changes from baseline.

[b] Employment impacts are based on input-output relationships and production impacts. Impacts on coke plant employment do not include jobs created by the relevant controls.

[c] Annual labor productivity in coal mining is estimated as 3,515 Mg per year per job.

TABLE C-24. INDUSTRY CAPITAL REQUIREMENTS OF REGULATORY ALTERNATIVES--FURNACE COKE, 1984

Regulatory Alternative	Capital costs of regulations,[a] 10^6 1984 $
II	38
III	68

[a] Calculated for all plants in operation in 1984.[44] [46]

Financial analysis is necessarily restricted to companies for which financial data are accessible. Therefore, financial analysis cannot be conducted for some privately owned companies for which reporting has been restricted. These companies are usually the smallest in a given industry, and they probably experience higher per unit costs of regulation and higher costs for securing financing than do larger companies.

A further complication of financial analysis is that many coke-producing companies are wholly owned subsidiaries of larger, highly diversified corporations. Financial data are available for the parent corporations only. Analysis of these data will probably lead to the conclusion that the parent companies have ample resources to finance additional capital costs. However, the extent to which these corporations will make such investments, or will cease some coke operations in favor of other investment opportunities evidencing higher rates of return, cannot be determined without knowledge of the required return on investment specific to the firm and the other investment opportunities that exist for the firm.

Table C-25 provides the capital costs as a percentage of average annual net investment by company for each regulatory alternative. The average annual net investment was calculated from financial records for each company by averaging net investment data (in constant 1983 dollars) for 1979 to 1983. These values are converted to 1984 dollars using an implicit GNP price deflator. In some instances, less than 5 years of data were available. In the case of subsidiaries, net investment of parent companies was used. The regulatory alternatives impose capital costs as percentages of average annual net investments between 0 and 5 percent.

Table C-26 shows capital cost as a percentage of cash flow for firms for which information was available. Cash flow data were derived from Table C-14. The values for 1983 were converted to 1984 dollars using an implicit GNP price deflator. As for net investment, in the case of subsidiaries, cash flow of parent companies was used. Capital costs as percentages of cash flows range from 0 to 8 percent for the regulatory alternatives.

The leverage ratios presented in Table C-15 indicate that coke-producing firms are engaged in a substantial amount of external financing. These firms may be reticent (or unable) to borrow more heavily, especially in the

TABLE C-25. CAPITAL COSTS OF COMPLIANCE AS A PERCENTAGE OF NET INVESTMENT--FURNACE COKE PRODUCERS, 1984[a]

Regulatory Alternative	Furnace coke producer[b]											
	A	B	C	D	E	F	G	H	I	J	K	L
II	1	1	0	1	3	1	2	1	1	1	0	1
III	2	2	0	2	5	1	3	3	1	2	1	2

[a] Average annual net income calculated from company profiles in *Moody's Industrial Manual*, Moody's Investor Service, New York, 1984, and *Standard New York Stock Exchange Reports*, Standard and Poor Corp., New York, 1984. (Calculations were made on a constant 1983 dollar basis and converted to 1984 values using a GNP implicit price deflator).

[b] Data on annual investment are not available for two companies.

TABLE C-26. CAPITAL COST AS A PERCENTAGE OF ANNUAL CASH FLOW--FURNACE COKE PRODUCERS, 1984[a]

Regulatory Alternative	Furnace coke producer[b]											
	A	B	C	D	E	F[c]	G	H	I	J[c]	K	L
II	4	5	0	2	2		2	1	0		0	0
III	8	8	0	5	4		4	1	1		1	1

[a] Cash flow data is from Table C-14 in Appendix C. Values are converted to 1984 dollars using a GNP implicit price deflator.

[b] There are three furnace coke producers for which cash flow data were not available.

[c] This company had negative cash flow.

current economic climate for steel. Furthermore, financing capital expenditures by issuing additional common stock would tend to dilute existing stockholder equity. Considering the low historical return on investment in the industry, this dilution probably would be unacceptable. An analysis of the iron and steel industry undertaken by TBS,[63] addressed the question of external financing with regard to water pollution control expenditures. This analysis concludes that to avoid deterioration in its financial condition, the industry is likely to reduce expenditures to modernize production facilities rather than increase its external financing.

In summary, the capital costs of the regulatory alternatives are in the tens of millions of dollars range. However, these amounts do not appear unduly burdensome when compared with normal investment expenditures or cash flow for companies for which data are available.

C.2.3.5 Battery and Plant Closures. Uneconomic batteries are those that have marginal costs of operation greater than the price of coke. Theoretically, these batteries are candidates for closure. There are 14 batteries operating in the uneconomic portion of the supply curve (above the point where priceline intersects the supply curve) under baseline conditions. They are owned by 10 companies and are located in 11 plants. Regulatory Alternative II does not add any companies or batteries to this list. Regulatory Alternative III forces one more battery owned by an additional company into the category of uneconomic batteries. It is important to note, however, that this does not necessarily imply that the regulation would cause the closure of this battery.

The decision to close a battery is more complicated than the basic closure rule would indicate; this is particularly true for integrated iron and steel producers. Continued access to profits from continued steel production is a key factor in the closure decision for a captive battery. Before closing or idling a coke battery, managers would want to know where they would get coke on a reliable basis in order to continue making steel. The obvious sources to be investigated include other plants within the same company, other companies, and foreign suppliers. As noted in Section C.1, some interregional and international movement of coke occurs.

Obtaining coke from offsite sources introduces two potential complications: the cost of transporting coke and the certainty of the coke supply. Obtaining coke from a nearby source might be the most profitable alternative to transporting coke. If coke must be shipped over long distances, onsite production at a cost above the projected market price might be more profitable.

If coke must be purchased, certainty of supply is a complication. Steel producers prefer to have captive sources of coke to safeguard against supply interruptions, and they may be willing to pay a premium for this security. Producing at a cost above market price would involve such a premium. Five of the fourteen uneconomic batteries under baseline compliance produce coke at marginal costs that are less than 5 percent above the market price. Five percent does not appear to be an excessive premium to pay for certainty of supply.

Several other factors could affect a particular plant's decision to close a battery. These factors relate to the relationship of coke quality to the type of steel commodities produced, the existence of captive coal mines, the costs of closing a battery and potential costs of restarting it in the future, and required control and other expenditures.

An alternative to closure for a financially troubled company is to file for Chapter 11 bankruptcy. This option allows firms to continue operating coke plants under a restructured debt payment schedule. Of firms owning the 14 uneconomic batteries under baseline, one has filed for Chapter 11, and another is expected to file in the future if the steel industry continues to sustain large losses.[88] This action may improve a firm's competitive situation. McLouth Steel Corporation, which filed for bankruptcy in 1982, has modernized equipment and reduced overhead to enable it to capture market share from larger companies.

The developed demand model uses a single coke price, which represents an average quality of coke used to produce a weighted average mix of steel products. If high production costs for a particular battery are associated with a higher than average quality of coke, continued production might be justified. Production also would be justified if the firm produces only the most highly valued steel products.

Some coke-producing firms also own coal mines and may wish to secure continued access to profits from coal mining. Because profits in the coal sector may be subject to less effective taxation because of depletion allowances, these profits may be extremely attractive.

Furthermore, an integrated iron and steel producer must consider the question of necessary expenditures for its entire steel plant. If the steel facility is old or if substantial additional expenditures will be necessary to comply with regulations on other parts of the facility, then closure is more likely.

Closure decisions are so specific to individual situations and managers' perceptions regarding their future costs and revenues that exact projections of closures should be viewed with caution. In the current market for steel, it is difficult to say whether uneconomic batteries will be closed. Of companies owning uneconomic batteries, three have cut back capacity by closing batteries, although it is unknown whether they are those projected as candidates for closure.[88]

C.2.4 Foundry Coke Impacts

Oven coke other than furnace coke represents less than 15 percent of U.S. coke production. The majority of it is used as a fuel in the cupolas of foundries. The remainder is used for a variety of purposes, especially for heating.

Values of various foundry coke variables in the absence of the regulatory alternatives are presented in Table C-27. These values assume baseline compliance with the regulations listed in the footnote to the table.

C.2.4.1 Price and Production Effects. In developing the estimates of price and quantity impacts, a vertical, nonparallel shift caused by each regulatory alternative has been projected in the linear estimate of the foundry coke supply function generated under the regulatory baseline. This shift is used in conjunction with an estimated elasticity demand for foundry coke of -1.03 and is designated Scenario A. Under this scenario, domestically produced foundry coke does not compete with imported coke. The reanalysis also estimates the effects of alternative regulations assuming that foundry coke producers must compete with imports in open market sales. In this case, consumers of foundry coke may purchase imported coke as a

TABLE C-27. BASELINE VALUES FOR ECONOMIC IMPACT ANALYSIS--FOUNDRY COKE, 1983

Coke market	Baseline values[a]
Price (1983 \$/Mg)	169.58[b]
Production (10^3 Mg)	2,951
Consumption (10^3 Mg)	2,938
Employment (jobs)[c]	542
Coal consumption (10^3 Mg)	3,809

[a] Baseline assumes companies meet existing regulations including OSHA (coke-oven emissions); State regulations on desulfurization, pushing, coal handling, coke handling, quench tower, and battery stack controls; and BPT and BAT water regulations.

[b] Calculated. Market price for foundry coke was $149.66 in the fourth quarter of 1983.

[c] Calculated. Foundry coke employment = Employment in byproduct coke industry × proportion of coke production represented by foundry coke sector.

perfect substitute for domestically produced coke. The price of imports is assumed to be constant. As regulations cause less domestic coke to be produced, its price relative to imported coke rises. Consumers are able to purchase as much coke as before at the same price, but a larger proportion of sales is made up of imports. Thus, there are quantity effects for domestic producers, but no price effects. This shift is designated Scenario B. Impacts are assessed for both scenarios. Impacts for Scenario B represent the maximum effect of import substitution in the foundry coke market.

The projected price and quantity effects are shown on Table C-28. Under Scenario A, both price and quantity impacts are less than 0.7 percent of baseline for Alternative II and less than 0.9 percent of baseline for Alternative III. Under Scenario B, there are no price impacts. Quantity impacts are 2.1 percent of baseline for Alternative II and 3.2 percent of baseline for Alternative III.

C.2.4.2 Coal Consumption and Employment Effects. Any reductions in foundry coke production are expected to cause reductions in the use of the factors that produce the foundry coke. The major inputs to foundry coke production are coal and labor. Labor is also an important input in coal mining.

The coal consumption and employment implications of the projected reductions in coke production are shown in Table C-29 for both scenarios. These values were developed assuming constant coal- and labor-output ratios. The employment impacts shown do not include any employment increases caused by the regulatory alternatives. Consequently, the employment impacts represent maximum values.

Under both scenarios and for all regulatory alternatives, effects on employment in the coal mining industry are negligible. Under Scenario A, neither Alternative II nor III results in coal consumption impacts or employment impacts in coke plants greater than a 1.2 percent change from baseline. Under Scenario B, coal consumption is reduced by 2.0 percent for Alternative II, and 3.2 percent for Alternative III. Employment in coke plants is reduced by about the same percentages from baseline.

C.2.4.3 Financial Effects. The aggregate capital costs of the regulatory alternatives are summarized in Table C-30. The capital requirements

TABLE C-28. PRICE AND QUANTITY EFFECTS OF REGULATORY ALTERNATIVES FOUNDRY COKE, 1984[a]

Regulatory Alternative	Coke price impact, 1984 $/Mg	Coke quantity impact, 10^3 Mg/yr
Scenario A		
II	0.99 (0.58)	-18 (-0.61)
III	1.46 (0.86)	-26 (-0.88)
Scenario B		
II	0.00 (0.00)	-61[b] (-2.07)
III	0.00 (0.00)	-94[b] (-3.18)[b]

[a] Values in parentheses are percentage changes from baseline.

[b] Coke consumption is not affected due to imports. Imports under Scenario B are equal in magnitude and of opposite sign to quantity impacts. Under Scenario A, imports are zero.

TABLE C-29. COAL CONSUMPTION AND EMPLOYMENT EFFECTS OF REGULATORY ALTERNATIVES--FOUNDRY COKE, 1984[a]

Regulatory Alternative	Coal consumption for coke, 10^3 Mg/yr	Employment (jobs)[b]	
		Coal mining[c]	Coke plant
Scenario A			
II	-23 (-0.78)	-6 (0.00)[d]	-3 (-0.55)
III	-34 (-1.16)	-9 (0.00)[d]	-5 (-0.92)
Scenario B			
II	-78 (-2.05)	-22 (-0.01)	-11 (-2.03)
III	-121 (-3.18)	-34 (-0.02)	-17 (-3.14)

[a] Values in parentheses are percentage changes from baseline.

[b] Employment impacts are based on input-output relationships and production impacts. Impacts on coke plant employment do not include jobs created by the relevant controls.

[c] Annual labor productivity in coal mining is estimated as 3,515 Mg/yr per job.

[d] Zero due to rounding.

TABLE C-30. INDUSTRY CAPITAL REQUIREMENTS OF REGULATORY ALTERNATIVES--FOUNDRY COKE, 1984

Regulatory Alternative	Capital costs of regulations,[a] 10^6 1984 $
II	7
III	12

[a] Calculated for all plants in operation in 1984.[48] [50]

to meet Regulatory Alternatives II and III for the foundry coke industry are $7 million and $12 million, respectively. Capital costs also have been summed across member plants to determine the cost to each company of meeting alternative regulations. These company capital costs, along with firm-specific financial data, are used to produce the same financial percentages as described above for furnace coke and total capital cost as a percentage of net capital investment and of annual cash flow. Financial data are not available for many of the foundry coke producers that are privately held companies. Therefore, percentages for these companies are not included in the analysis.

Capital costs as percentages of average annual net investment for the foundry coke producers are provided in Table C-31. The costs of moving from baseline to a regulatory alternative are never more than 11 percent of the average annual net investment. Foundry coke production plants operate at a significantly lower production rate for the same level of investment as compared with furnace coke production rates. This is due to the longer coking time for foundry coke. Furthermore, in looking at the available data on the age of the batteries used in the production processes within each plant, there appears to be a correlation between the age of the battery used and the level of compliance costs facing the firm. The data suggest that the foundry coke producing plants that are facing the highest pending compliance costs are operating with batteries installed between 1919 and 1946. Conversely, the foundry coke producers that are facing the lowest pending compliance costs are operating, for the most part, with batteries installed between 1950 and 1979.

Table C-32 provides capital cost as a percentage of annual cash flow. The regulatory alternatives result in capital costs no greater than 2 percent of cash flow for foundry coke producers for which information is available.

Firms would use internal financing, additional equity financing, debt financing, or perhaps some of the methods mentioned in Section C.1.5, to make these capital expenditures. Because many of the foundry plants are owned by private corporations, data are insufficient to assess the eventual sources of capital that these firms will use. Therefore, only qualitative statements can be made concerning the impacts of financing regulatory

TABLE C-31. CAPITAL COSTS OF COMPLIANCE AS A PERCENTAGE OF NET INVESTMENT--FOUNDRY COKE PRODUCERS, 1984[a]

Regulatory Alternative	Foundry coke producers[b]		
	AA	BB	CC
II	4	0	0
III	11	1	1

[a] Average annual net investment calculated from company profiles in Moody's Industrial Manual, Moody's Investor Service, New York, 1984; Standard New York Stock Exchange Reports, Standard and Poor's Corp., New York, 1984; and Dun and Bradstreet Financial Profiles, 1985. (Calculations were made on a constant 1983 dollar basis and converted to 1984 dollars using a GNP implicit price deflator.)

[b] There are eight foundry coke producers for which annual investment data are not available.

TABLE C-32. CAPITAL COST AS A PERCENTAGE OF ANNUAL CASH FLOW--FOUNDRY COKE PRODUCERS, 1984[a]

	Foundry coke producers[b]			
Regulatory Alternative	AA	BB	CC	DD
II	1	0	0	1
III	1	1	1	1

[a] Cash flow data are from Table C-14 in Appendix C. Values are converted to 1984 dollars using a GNP implicit price deflator.

[b] There are six foundry coke producers for which cash flow data are not available.

investments. Any internal financing would reduce return on equity by directly reducing dividends or by reducing productive capital expenditures. Debt financing may reduce the return on equity by increasing the cost of debt financing. Financing regulatory capital requirements using new common stock issues will have a tendency to dilute present owner's equity. This dilution could be substantial. As an alternative, one foundry coke firm entered bankruptcy status. No information on the competitive status of this firm is available. In the firms for which data are available, the capital requirements of the regulatory alternative do not appear unduly burdensome.

C.2.4.4 Battery and Plant Closures. The decision rule used to indicate closure candidates among furnace batteries also is used for foundry batteries. Any foundry battery for which the marginal cost of operation is greater than the price of foundry coke is an uneconomic battery. According to this criterion and assuming baseline control, no batteries that were in operation in 1984 are uneconomic to operate. The regulatory alternatives do not cause any batteries to move into the uneconomic region under either scenario.

C.3. POTENTIAL SOCIOECONOMIC AND INFLATIONARY IMPACTS

C.3.1 Compliance Costs

The estimated total annualized costs to coke producers for compliance with the regulatory alternatives are shown in Tables C-33 and C-34. Costs for furnace and foundry producers are differentiated because of differences in coke prices and control costs per unit of output. The costs are for all plants in operation in 1984 are calculated.

As shown in Table C-33, in 1984, Regulatory Alternative II would result in compliance costs of $3.5 million per year for furnace coke producers. Regulatory Alternative III would result in compliance costs of $12.4 million per year for furnace coke producers.

Compliance costs for foundry coke producers is shown in Table C-34. For Regulatory Alternative II, this cost is $1.3 million per year. For Regulatory Alternative III, compliance cost is $2.9 million per year. Combined compliance cost for furnace and foundry coke producers is $4.8 million per year for Regulatory Alternative II. For Regulatory Alternative III, this cost is $15.3 million per year.

TABLE C-33. COMPLIANCE COSTS OF REGULATORY ALTERNATIVES--FURNACE COKE PRODUCERS, 1984

Regulatory Alternative	Compliance cost, 10^6 1984 \$/yr
II	3.5
III	12.4

TABLE C-34. COMPLIANCE COSTS OF REGULATORY ALTERNATIVES--FOUNDRY COKE PRODUCERS, 1984

Regulatory Alternative	Compliance cost, 10^6 1984 \$/yr
II	1.3
III	2.9

C.3.3 Balance of Trade

Recent trends indicate that imports are decreasing. Imposition of the regulatory alternatives is expected to slightly reverse this trend. Some increase in steel imports is possible also. However, because steel price increases caused by coke price increases are projected to be quite small, any increase in imports caused by the regulatory alternatives should be minor. Moreover, trade regulations covering steel imports may mitigate such increases.

In the aggregate, it appears unlikely that these regulatory alternatives would significantly affect the U.S. balance of trade position, given the small share of international trade represented by coke imports.

C.3.4 Community Impacts

Furnace and foundry coke and steel production facilities are in Pennsylvania, Indiana, Ohio, Maryland, New York, Michigan, Illinois, Alabama, Utah, Kentucky, Tennessee, Texas, Missouri, Wisconsin, and West Virginia. Closure of coke facilities, if they occur, could have impacts on communities in these States. The regulatory alternatives are not necessarily projected to result in closures. Potential production decreases should not be sufficient to generate significant community impacts. However, further compliance with proposed regulations could result in additional battery and plant closures and the resulting community impacts.

C.3.5 Small Business Impacts

The Regulatory Flexibility Act (RFA) requires consideration of the potential impacts of proposed regulations on small "entities." A regulatory flexibility analysis is required for regulations that have a "significant economic impact on a substantial number of small entities." For the NESHAP for coke oven by-product plants, small entities can be defined as small furnace and foundry coke firms. This section addresses the requirements that relate to the economic aspects of the RFA. Steps necessary for determination of applicability of the RFA are:

- Identification of small firms impacted by the NESHAP
- Estimation of the economic impact of the NESHAP on these small firms.

The guidelines for conducting a regulatory flexibility analysis define a small business as "any business concern which is independently owned and operated and not dominant in its field as defined by the Small Business Administration Regulations under Section 3 of the Small Business Act." The Small Business Administration (SBA) defines small firms in terms of employment. Firms owning coke ovens are included in SIC 3312, which also includes blast furnaces, steel works, and rolling mills. The SBA has determined that any firm that is in SIC 3312 and employs fewer than 1,000 workers will be considered small under the Small Business Act.

Table C-35 shows employment data for all U.S. firms that operate by-product coke ovens. Six firms in the list--9, 14, 16, 19, 20, and 23--can be designated as small based on SBA definitions. Because the standard being proposed is a NESHAP and all existing and new plants will be expected by law to comply, all plants of the small firms not currently in compliance could be adversely impacted. A "substantial number" of small business is defined as "more than 20 percent of these entities." This rule implies that at least two firms be impacted to qualify as a "substantial number."

After the affected small firms are identified, the guidelines for the RFA require an estimate of the degree of economic impact. Four criteria are applied in assessing whether significant economic impact occurs from the regulation. The first criterion determines whether annual compliance costs increase average total production costs of small entities by more than 5 percent. None of the small firms identified was found to have an average cost increase greater than 5 percent.

A second criterion compares compliance costs as a percentage of sales for small entities with the same percentage for large entities. If the result for small entities is at least 10 percentage points higher than for large firms, the impact is considered significant. Based on net sales data in Table C-14 and compliance cost data in Tables C-31 and C-32, one small company is significantly impacted. It should be noted that sales data are not available for all small entities.

The third criterion for assessing significant impact is whether capital costs of compliance represent a "significant" portion of capital available to small entities. The criterion recommends examining internal cash flow

TABLE C-35. EMPLOYMENT DATA FOR U.S. FIRMS OPERATING COKE OVENS, 1983

Company	Employment
1	48,071
2	52,800
3	28,700
4	9,107
5	163,356
6	37,300
7	16,000
8	32,000
9	210
10	1,300
11	2,400
12	19,200
13	7,300
14	102
15	7,512
16	164
17	1,245
18	98,722
19	150
20	150
21	14,518
22	2,200
23	200

in addition to external sources of financing. Small, privately owned firms often do not report their annual investment expenditures, so that determination of capital availability is impossible. No financial data could be located for the small coke-producing firms previously identified.

The final criterion is whether the requirements of the regulation are likely to result in closures of small entities. None of the small firms identified is projected to close as a result of the regulatory alternatives.

The regulatory alternatives are unlikely to result in adverse economic impact on a "substantial number" of small entities (as defined by SBA). Based on the four criteria used by EPA for which assessment may be made, one firm may be "significantly impacted" under the second criterion. No significantly impacted firms were identified under the other rules.

C.3.6 Energy

The regulatory alternatives do not have any significant direct energy impacts. Although some indirect impacts are possible, they are likely to be minor in nature.

Indirect impacts could include the substitution of fossil fuels for coke in blast furnaces or an increase in use of electric furnaces, further reducing the coke rate. Some reduction is projected to occur in any case, but technological limits govern the degree to which the coke rate can be reduced. Furthermore, projected coke price increases are minor when compared to recent and projected fossil fuel price increases. Of course, if imports increase, fuel will be needed to transport them. Furthermore, if imports replace domestic coke production, excess coke oven gas, some of which currently is used in other parts of the steel plant, may be replaced by other fuels. But if steel production decreases, there will be some reduction in fuel consumption.

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Appendix D

Health Risk Impact Analysis

APPENDIX D: HEALTH RISK IMPACT ANALYSIS

D.1 REVISED INPUT DATA

The health risk impact analysis was repeated after proposal of the standards because of revisions to the baseline data regarding plant capacities and emission factors for foundry plants (as described in Chapter 6 of this document). In addition, EPA made more accurate estimates of the latitudes and longitudes of plant locations by examining U.S. Geological Survey topographical maps. These revised input data are shown on Tables D-1 and D-2.

The EPA also developed stack parameters for modeling the control option of wash-oil scrubbers that would achieve 90-percent emission reduction; they are shown on Table D-3. The stack parameters for baseline and other control options have not changed since the analysis performed before proposal.

The unit risk estimate has been revised since proposal to 0.026/ppm. This revision is described in Chapter 9 of this document. The revised estimate was used in the updated calculation of incidence and maximum lifetime risk.

D.2 METHODOLOGY

The Human Exposure Model was used to generate revised risk estimates, as was used for the preproposal analysis. This methodology was described in Appendix E of the proposal BID.

After the computer modeling was completed, the estimates for the three furnace and three foundry plants with the highest values for maximum lifetime risk were examined further. A detailed check was made to determine whether the location of the most exposed individual was realistically placed by the computer. A review of the U.S. Geological Survey maps revealed that, at four of these six plants, there appeared to be no possible residential sites where the computer placed the most exposed individuals. Therefore, the points of maximum exposure were modified for the baseline and controlled cases at these four plants.

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TABLE D-1. FURNACE COKE BY-PRODUCT RECOVERY PLANTS LOCATION AND BENZENE EMISSIONS (kg/yr) FOR REGULATORY BASELINE

No.	Plant	Latitude	Longitude	Coke production capacity, 1,000 Mg/yr	Tar decanter	Tar storage	Excess ammonia-liq. tank	Light-oil storage	Light-oil sump	Light-oil cond. vent	Wash-oil decanter	Wash-oil circ. tank
1	LTV Steel, Thomas, AL	33°32'47"	86°50'13"	315	2.43E+04	3.78E+03	2.84E+03	1.83E+03	4.73E+03	2.80E+04	1.20E+03	1.20E+03
2	New Boston, Portsmouth, OH	38°44'57"	82°56'01"	364	2.80E+04	4.37E+03	3.28E+03	2.11E+03	5.46E+03	3.24E+04	1.38E+03	1.38E+03
3	Wheeling-Pitt, Monessen, PA	40°09'46"	79°53'47"	490	3.77E+04	5.88E+03	4.41E+03	2.84E+03	7.35E+03	4.36E+04	1.86E+03	1.86E+03
4	Lone Star Steel, Lone Star, TX	32°54'59"	94°42'57"	507	3.90E+04	6.08E+03	4.56E+03	2.94E+03	7.61E+03	4.51E+04	1.93E+03	1.93E+03
5	LTV Steel, So. Chicago, IL	41°41'29"	87°32'50"	563	4.34E+04	6.76E+03	5.07E+03	3.27E+03	8.45E+03	5.01E+04	2.14E+03	2.14E+03
6	National Steel, Granite City, IL	38°41'40"	90°07'42"	570	4.39E+04	6.84E+03	5.13E+03	3.31E+03	8.55E+03	5.07E+04	2.17E+03	2.17E+03
7	Interlake, Chicago, IL	41°39'22"	87°37'32"	582	4.48E+04	6.98E+03	5.24E+03	3.38E+03	8.73E+03	5.18E+04	2.21E+03	2.21E+03
8	LTV Steel, Gadsden, AL	34°00'46"	86°02'38"	758	5.84E+04	9.10E+03	6.82E+03	4.40E+03	1.14E+04	6.75E+04	2.88E+03	2.88E+03
9	Rouge Steel, Dearborn, MI	42°18'19"	83°09'40"	778	5.99E+04	9.34E+03	7.00E+03	4.51E+03	1.17E+04	6.92E+04	2.96E+03	2.96E+03
10	U.S. Steel, Fairless Hills, PA	40°09'28"	74°44'32"	916	7.05E+04	1.10E+04	8.24E+03	5.31E+03	1.37E+04	8.15E+04	3.48E+03	3.48E+03
11	LTV Steel, Warren, OH	41°13'13"	80°48'40"	945	7.28E+04	1.13E+04	8.51E+03	5.48E+03	1.42E+04	8.41E+04	3.59E+03	3.59E+03
12	LTV Steel, E. Chicago, IN	41°39'48"	87°26'42"	948	7.30E+04	1.14E+04	8.53E+03	5.50E+03	1.42E+04	8.44E+04	3.60E+03	3.60E+03
13	Armco Inc., Ashland, KY	38°30'07"	82°40'08"	963	7.42E+04	1.16E+04	8.67E+03	5.59E+03	1.44E+04	8.57E+04	3.66E+03	3.66E+03
14	Weirton Steel, Brown's Is., WV	40°24'58"	80°35'16"	1,097	8.45E+04	1.32E+04	9.87E+03	6.36E+03	1.65E+04	9.76E+04	4.17E+03	4.17E+03
15	U.S. Steel, Provo, UT	40°18'43"	111°44'31"	1,160	8.93E+04	1.39E+04	1.04E+04	6.73E+03	1.74E+04	1.03E+05	4.41E+03	4.41E+03
16	LTV Steel, Aliquippa, PA	40°37'16"	80°14'24"	1,218	9.38E+04	1.46E+04	1.10E+04	7.06E+03	1.83E+04	1.08E+05	4.63E+03	4.63E+03
17	Bethlehem Steel, Lackawanna, NY	42°49'20"	78°51'11"	1,292	9.95E+04	1.55E+04	1.16E+04	7.49E+03	1.94E+04	1.15E+05	4.91E+03	4.91E+03
18	National Steel, Detroit, MI	42°15'16"	83°07'43"	1,397	1.08E+05	1.68E+04	1.26E+04	8.10E+03	2.10E+04	1.24E+05	5.31E+03	5.31E+03
19	U.S. Steel, Lorain, OH	41°26'56"	82°07'50"	1,496	1.15E+05	1.80E+04	1.35E+04	8.68E+03	2.24E+04	1.33E+05	5.68E+03	5.68E+03
20	Wheeling-Pitt, E. Steubenville, WV	40°20'36"	80°36'25"	1,509	1.16E+05	1.81E+04	1.36E+04	8.75E+03	2.26E+04	1.34E+05	5.73E+03	5.73E+03
21	LTV Steel, Cleveland, OH	41°28'26"	81°39'55"	1,760	1.36E+05	2.11E+04	1.58E+04	1.02E+04	2.64E+04	1.57E+05	6.69E+03	6.69E+03
22	Armco Inc., Middletown, OH	39°29'45"	84°23'15"	1,776	1.37E+05	2.13E+04	1.60E+04	1.03E+04	2.66E+04	1.58E+05	6.75E+03	6.75E+03
23	Bethlehem Steel, Burns Harbor, IN	41°37'41"	87°10'20"	1,790	1.38E+05	2.15E+04	1.61E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
24	LTV Steel, Pittsburgh, PA	40°25'34"	79°57'47"	1,792	1.38E+05	2.15E+04	1.61E+04	1.04E+04	2.69E+04	1.59E+05	6.81E+03	6.81E+03
25	U.S. Steel, Fairfield, AL	33°29'22"	86°55'32"	1,822	1.40E+05	2.19E+04	1.64E+04	1.06E+04	2.73E+04	1.62E+05	6.92E+03	6.92E+03
26	Bethlehem Steel, Bethlehem, PA	40°36'51"	75°21'13"	2,253	1.73E+05	2.70E+04	2.03E+04	2.61E+04	3.38E+04	2.01E+05	8.56E+03	8.56E+03
27	Bethlehem Steel, Sparrows Pt., MD	39°13'10"	76°29'19"	3,506	2.70E+05	4.21E+04	3.16E+04	2.03E+04	5.26E+04	3.12E+05	2.66E+02	2.66E+02
28	Inland Steel, E. Chicago, IN	41°37'53"	87°27'15"	3,715	2.86E+05	4.46E+04	3.34E+04	2.15E+04	5.57E+04	3.31E+05	1.41E+04	1.41E+04
29	U.S. Steel, Gary, IN	41°36'55"	87°20'03"	4,228	3.26E+05	5.07E+04	3.81E+04	2.45E+04	6.34E+04	3.76E+05	1.61E+04	1.61E+04
30	U.S. Steel, Clairton, PA	40°18'04"	79°52'21"	5,294	4.08E+05	6.35E+04	4.76E+04	3.07E+04	7.94E+04	9.42E+03	2.01E+04	2.01E+04
	Totals			45,804	3.53E+06	5.50E+05	4.12E+05	2.42E+05	6.60E+05	3.46E+06	1.54E+05	1.54E+05

Note: Data current as of November 1984.

(continued)

TABLE D-1. (continued)

Plant No.	Leaks	Tar dewatering	Flushing-liquor circ. tank	Benzene storage	Denver flo unit	Naphth. melt pit	Naphth. dry tank	TBFC	DWFC	BTX storage	Tar inc. sump	Total Benzene By Plant kg/yr
1	2.46E+04	6.62E+03	2.84E+03	0.00E+00	2.74E+04	6.30E+03	3.15E+01	0.00E+00	8.51E+04	0.00E+00	2.99E+04	2.51E+05
2	2.46E+04	7.64E+03	3.28E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.55E+04	0.00E+00	0.00E+00	3.46E+04	1.74E+05
3	2.46E+04	1.03E+04	4.41E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.43E+04	0.00E+00	0.00E+00	4.66E+04	2.26E+05
4	2.46E+04	1.06E+04	4.56E+03	0.00E+00	4.41E+04	1.01E+04	5.07E+01	0.00E+00	1.37E+05	2.94E+03	4.82E+04	3.91E+05
5	5.74E+04	0.00E+00	5.07E+03	3.27E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.27E+03	5.35E+04	2.44E+05
6	2.46E+04	1.20E+04	5.13E+03	0.00E+00	4.95E+04	1.14E+04	5.70E+01	0.00E+00	1.54E+05	3.31E+03	5.42E+04	4.37E+05
7	2.46E+04	1.22E+04	5.24E+03	0.00E+00	5.06E+04	1.16E+04	5.82E+01	0.00E+00	1.57E+05	0.00E+00	5.53E+04	4.42E+05
8	2.46E+04	1.59E+04	6.82E+03	0.00E+00	6.59E+04	1.52E+04	7.58E+01	0.00E+00	2.05E+05	0.00E+00	7.20E+04	5.68E+05
9	2.46E+04	1.63E+04	7.00E+03	0.00E+00	6.76E+04	1.56E+04	7.78E+01	0.00E+00	2.10E+05	4.51E+03	7.39E+04	5.87E+05
10	2.46E+04	1.92E+04	8.24E+03	0.00E+00	7.96E+04	1.83E+04	9.16E+01	0.00E+00	2.47E+05	0.00E+00	8.70E+04	6.82E+05
11	2.46E+04	1.98E+04	8.51E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.98E+04	3.46E+05
12	2.46E+04	1.99E+04	8.53E+03	0.00E+00	8.24E+04	1.90E+04	9.48E+01	0.00E+00	2.56E+05	5.50E+03	9.01E+04	7.10E+05
13	2.46E+04	2.02E+04	8.67E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	9.15E+04	3.52E+05
14	2.46E+04	2.30E+04	9.87E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.36E+03	1.04E+05	4.04E+05
15	5.74E+04	2.44E+04	1.04E+04	6.73E+03	0.00E+00	0.00E+00	0.00E+00	8.12E+04	0.00E+00	0.00E+00	1.10E+05	5.40E+05
16	2.46E+04	2.56E+04	1.10E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.16E+05	4.39E+05
17	2.46E+04	2.71E+04	1.16E+04	0.00E+00	1.12E+05	2.58E+04	1.29E+02	0.00E+00	3.49E+05	7.49E+03	1.23E+05	9.59E+05
18	2.46E+04	2.93E+04	1.26E+04	0.00E+00	1.21E+05	2.79E+04	1.40E+02	0.00E+00	3.77E+05	0.00E+00	1.33E+05	1.03E+06
19	2.46E+04	3.14E+04	1.35E+04	0.00E+00	1.30E+05	2.99E+04	1.50E+02	0.00E+00	4.04E+05	0.00E+00	1.42E+05	1.10E+06
20	2.46E+04	3.17E+04	1.36E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.43E+05	5.38E+05
21	2.46E+04	3.70E+04	1.58E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.02E+04	1.67E+05	6.34E+05
22	2.46E+04	3.73E+04	1.60E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.80E+05	1.03E+04	1.69E+05	1.12E+06
23	0.00E+00	3.76E+04	1.61E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.70E+05	3.99E+05
24	2.46E+04	3.76E+04	1.61E+04	0.00E+00	1.56E+05	3.58E+04	1.79E+02	0.00E+00	4.84E+05	0.00E+00	1.70E+05	1.31E+06
25	2.46E+04	3.83E+04	1.64E+04	0.00E+00	1.58E+05	3.64E+04	1.82E+02	0.00E+00	4.92E+05	0.00E+00	1.73E+05	1.33E+06
26	2.46E+04	4.73E+04	2.03E+04	0.00E+00	1.96E+05	4.51E+04	2.25E+02	0.00E+00	6.08E+05	2.51E+02	2.14E+05	1.63E+06
27	5.74E+04	7.36E+04	3.16E+04	2.03E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.33E+05	1.25E+06
28	2.46E+04	7.80E+04	3.34E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.60E+05	0.00E+00	0.00E+00	3.53E+05	1.55E+06
29	2.46E+04	8.88E+04	3.81E+04	0.00E+00	3.67E+05	8.46E+04	4.23E+02	0.00E+00	1.14E+06	0.00E+00	4.02E+05	3.06E+06
30	5.74E+04	0.00E+00	4.76E+04	3.07E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	5.03E+05	1.32E+06
Total	8.45E+05	8.39E+05	4.12E+05	6.10E+04	1.71E+06	3.93E+05	1.97E+03	4.01E+05	5.79E+06	5.41E+04	4.35E+06	2.40E+07

Note: Data current as of November 1984.

TABLE D-2. FOUNDRY COKE BY-PRODUCT RECOVERY PLANTS LOCATION AND BENZENE EMISSIONS (kg/yr) FOR REGULATORY BASELINE

No.	Plant	Latitude	Longitude	Coke production capacity, 1,000 Mg/yr	Tar decanter	Tar storage	Excess ammonia liq. tank	Light-oil storage	Light-oil sump	Light-oil cond. vent	Wash-oil decanter	Wash-oil circ. tank
1.	Chattanooga Coke, Chattanooga, TN	35°02'16"	85°18'11"	130	4.70E+03	7.33E+02	8.54E+02	4.07E+02	1.05E+03	6.25E+03	2.67E+02	2.67E+02
2.	IN Gas, Terre Haute, IN	39°26'48"	87°23'47"	132	4.78E+03	7.44E+02	8.67E+02	4.13E+02	1.07E+03	6.34E+03	2.71E+02	2.71E+02
3.	Koppers, Toledo, OH	41°40'10"	83°29'31"	157	5.68E+03	8.85E+02	1.03E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
4.	Empire Coke, Holt, AL	33°14'25"	87°30'11"	161	5.83E+03	9.08E+02	1.06E+03	5.04E+02	1.30E+03	7.74E+03	3.30E+02	3.30E+02
5.	Koppers, Erie, PA	42°08'43"	80°01'32"	207	7.49E+03	1.17E+03	1.36E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
6.	Tonawanda, Buffalo, NY	42°58'56"	78°56'19"	299	1.08E+04	1.69E+03	1.96E+03	9.36E+02	2.42E+03	1.44E+04	6.14E+02	6.14E+02
7.	Carondolet, St. Louis, MO	38°32'08"	90°16'05"	330	1.19E+04	1.86E+03	2.17E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
8.	AL Byproducts, Keystone, PA	40°05'12"	75°18'59"	402	1.45E+04	2.27E+03	2.64E+03	1.26E+03	3.26E+03	1.93E+04	8.25E+02	8.25E+02
9.	Citizens Gas, Indianapolis, IN	39°45'16"	86°06'49"	477	1.73E+04	2.69E+03	3.13E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
10.	Jim Walters, Birmingham, AL	33°33'16"	86°48'38"	499	1.81E+04	2.81E+03	3.28E+03	1.56E+03	4.04E+03	2.40E+04	1.02E+03	1.02E+03
11.	Shenango, Pittsburgh, PA	40°28'49"	80°03'34"	521	1.89E+04	2.94E+03	3.42E+03	1.63E+03	4.22E+03	2.50E+04	1.07E+03	1.07E+03
12.	Koppers, Woodward, AL	33°26'13"	86°57'50"	563	2.04E+04	3.18E+03	3.70E+03	1.76E+03	4.56E+03	2.71E+04	1.16E+03	1.16E+03
13.	AL Byproducts, Tarrant, AL	33°34'57"	86°46'47"	583	2.11E+04	3.29E+03	3.83E+03	1.83E+03	4.72E+03	2.80E+04	1.20E+03	1.20E+03
14.	Detroit Coke, Detroit, MI	42°11'19"	83°09'16"	617	2.23E+04	3.48E+03	4.05E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Totals			5,078	1.84E+05	2.86E+04	3.34E+04	1.03E+04	2.66E+04	1.58E+05	6.75E+03	6.75E+03

Note: Data current as of November 1984.

(continued)

TABLE D-2. (continued)

Plant no.	Leaks	Tar dewatering	Flushing-liquor circ. tank	Benzene storage	Denver flo unit	Naphth. melt pit	Naphth. dry tank	TBFC	DWFC	BTX storage	Tar inc. sump	Total Benzene by plant kg/yr
1	2.24E+04	1.28E+03	8.54E+02	0.00E+00	8.25E+03	1.90E+03	9.49E+00	0.00E+00	2.56E+04	0.00E+00	5.80E+03	8.06E+04
2	2.24E+04	1.30E+03	8.67E+02	0.00E+00	8.37E+03	1.93E+03	9.64E+00	0.00E+00	2.60E+04	0.00E+00	5.89E+03	8.15E+04
3	0.00E+00	1.55E+03	1.03E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.02E+03	0.00E+00	0.00E+00	7.01E+03	2.52E+04
4	2.24E+04	0.00E+00	1.06E+03	0.00E+00	1.02E+04	2.35E+03	1.18E+01	0.00E+00	3.17E+04	0.00E+00	7.19E+03	9.29E+04
5	0.00E+00	2.04E+03	1.36E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	9.24E+03	2.27E+04
6	2.24E+04	2.95E+03	1.96E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.34E+04	7.41E+04
7	0.00E+00	3.26E+03	2.17E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.47E+04	3.61E+04
8	5.22E+04	3.97E+03	2.64E+03	1.26E+03	2.55E+04	5.87E+03	2.93E+01	0.00E+00	7.92E+04	1.26E+03	1.79E+04	2.35E+05
9	0.00E+00	4.71E+03	3.13E+03	0.00E+00	3.03E+04	6.96E+03	3.48E+01	0.00E+00	9.40E+04	0.00E+00	2.13E+04	1.84E+05
10	2.24E+04	4.93E+03	3.28E+03	0.00E+00	3.17E+04	7.29E+03	3.64E+01	0.00E+00	9.84E+04	1.56E+03	2.23E+04	2.48E+05
11	2.24E+04	5.14E+03	3.42E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.33E+04	1.12E+05
12	2.24E+04	5.56E+03	3.70E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.88E+04	0.00E+00	0.00E+00	2.51E+04	1.48E+05
13	2.24E+04	5.75E+03	3.83E+03	0.00E+00	3.70E+04	8.51E+03	4.26E+01	0.00E+00	1.15E+05	0.00E+00	2.60E+04	2.84E+05
14	0.00E+00	6.09E+03	4.05E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.75E+04	6.76E+04
Total	2.31E+05	4.85E+04	3.34E+04	1.26E+03	1.51E+05	3.48E+04	1.74E+02	3.68E+04	4.70E+05	2.82E+03	2.27E+05	1.69E+06

Note: Data current as of November 1984.

TABLE D-3. PARAMETERS FOR 90% EMISSION REDUCTION OPTION (WASH-OIL SCRUBBER)

Source	Scrubber height, m[a]	Vertical cross-sectional area, m^2[a]	Diameter of vent, m	Stack gas velocity, m/s[b]	Stack gas temperature, °K[c]
Storage tanks for Light oil, BTX, or benzene	4.3	23.6	0.191	0.46	305
Excess ammonia-liquor tank	10.1	101.9	0.191	0.46	305
Tar storage	12.3	240.0	0.191	1.149	311
Tar dewatering tanks	12.3	240.0	0.191	1.149	311
Tar decanter, tar intercepting sump, and flushing-liquor circulation tank[d]	4.6	29.2	0.191	1.149	311
Light-oil condenser vent, wash-oil decanter, wash-oil circulation tank[e]	4.3	23.6	0.191	1.149	305

[a] Assumed wash-oil scrubber attached to the side of the source and is the same height and same vertical cross-sectional area

[b] Stack gas velocity derived from costing design flow of 0.013 m^3/s for storage tanks containing light oil, BTX, or benzene and the excess ammonia liquor tank, and from costing design flow of 0.03 m^3/s for other sources, which have greater emissions.

[c] Stack gas temperature is the temperature of cool wash oil for sources with cool gases and is slightly higher (38 °C) for sources with hot gases.

[d] Assumes this group of sources all vented to one scrubber attached to the flushing-liquor circulation tank.

[e] Assumes this group of sources all vented to one scrubber attached to the wash-oil circulation tank.